

APPENDIX A

CALCULATIONS OF LANDFILL GAS ENERGY RECOVERY PROJECT COSTS

This Appendix contains sample cost estimates and calculations for three landfill sizes—1, 5, and 10 million metric tons of waste in place. The cost data are intended to illustrate the types of cost items that should be included when evaluating project economics. The actual costs of a specific project are dependent on project configuration, design, equipment selection, location, and site-specific factors. Thus, a qualified engineer should be consulted when considering investing in a landfill gas energy recovery project.

This Appendix contains 20 tables. Tables A.1 through A.14 present costs and calculations for a landfill gas power project, and Tables A.15 through A.20 present costs and calculations for a medium-Btu gas project. Tables A.1 through A.10 contain capital and O&M cost information for each of the landfill sizes. The remainder of the power project tables—Tables A.11 through A.14—contain sample comparisons of expenses and revenues for a 5 million metric ton landfill power project. Project finance and municipal bond finance cases are included.

TABLE A.1 SUMMARY OF ESTIMATED POWER PROJECT CAPITAL COSTS

LANDFILL SIZE Waste in Place	Estimated Net Sustainable LFG Production (mcf/day)	Net Electric Output (kW)	CAPITAL COSTS			
			Installed LFG Collection System (\$/kW)	Installed Energy Conversion System (\$/kW)	Total Soft Costs + Engineering (\$/kW)	Incremental Capital Requirement (\$/kW)
					(a)	(b)
1 million metric tons						
IC Engine	642	984	\$638	\$1,052	\$310	\$1,283
Combustion Turbine	642	963	\$652	\$1,412	\$359	\$1,691
5 million metric tons						
IC Engine	2,988	4,934	\$423	\$958	\$294	\$1,177
Combustion Turbine	2,988	4,727	\$442	\$1,153	\$334	\$1,409
Combined Cycle CT	2,988	6,763	\$309	\$1,360	\$356	\$1,658
10 million metric tons						
IC Engine	5,266	8,709	\$413	\$919	\$263	\$1,109
Combustion Turbine	5,266	8,344	\$431	\$1,037	\$288	\$1,249
Combined Cycle CT	5,266	12,008	\$300	\$1,208	\$306	\$1,458

Notes:

Source is cost calculation tables for each size landfill.

All costs are based on net electric (kW) output.

(a) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (6 - 24 mos) and interest during construction.

(b) Excludes capital and soft costs associated with the LFG collection system.

TABLE A.2 ESTIMATED CAPITAL COSTS (1 million Mg case)

Example: Landfill waste in place = 1 million metric tons				
Cost Category	Units	IC Engine	Combustion Turbine	
OPERATING DATA				
Net sustainable landfill gas production	mcf/day	642	642	(a)
Gross electric output	kW	1,029	1,029	(b)
Auxiliary and compressor loads	kW	46	66	(c)
Net electric output	kW	984	963	
On-line date		6/96	6/96	
Capacity factor (lifetime annual average)		80%	80%	(d)
Annual full load operating hours	hours	7,008	7,008	
Annual electricity generated	kWh	6,895,872	6,748,704	
EQUIPMENT & INSTALLATION COSTS				
Energy Conversion System (\$1994)				
Engine, auxiliaries, construction	\$000	825	1,050	(e)
Interconnections (elec, water, LFG)	\$000	110	110	(f)
Gas compressor	\$000	100	200	
Energy conversion system cost	\$000	1,035	1,360	
LFG collection system cost (\$1994)	\$000	628	628	(g)
Engineering (\$1994) @ 5.0%	\$000	83	99	(h)
CAPITAL REQUIREMENT				
System cost (\$1994)	\$000	1,746	2,087	
Soft Costs				
Owners costs, escalation, interest		135	142	(i)
Contingency @ 5.0%		87	104	
Total Soft Costs	\$000	222	246	
Total Capital Requirement	\$000	1,968	2,333	
(as-spent dollars, 1996 on-line date)	\$/kW net	2,000	2,423	
Incremental Capital Requirement	\$000	1,263	1,628	(j)
(as-spent dollars, 1996 on-line date)	\$/kW net	1,283	1,691	

Notes:

- (a) Based on landfill size of approximately 1 million metric tons. [EPA] (mcf = thousand cubic feet)
1 cf landfill gas = 0.5 cf methane
- (b) $\text{kW} = (\text{cf/hr methane}) \times (1000 \text{ Btu/cf}) / (13,000 \text{ Btu/kWh})$
- (c) Compressor effects: IC engine -- 2% parasitic load; CTs -- 4% parasitic load
- (d) Conservative estimated capacity factor over project life. [EPA]
- (e) Includes prime mover, generator, plant auxiliaries, construction, LFG modifications, emissions controls.
- (f) Assumed to be \$100,000 for electric, \$10,000 for water.
- (g) Calculated based on EPA Exhibit 4-7; includes collection system + flare. [EPA]
- (h) Calculated as 5% of conversion and collection system costs.
- (i) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (6 mos) and interest during construction.
- (j) Excludes capital and soft costs associated with the LFG collection system.

TABLE A.3 ESTIMATED COST OF ELECTRICITY (1 million Mg case)
Project Finance Case

Example: Landfill waste in place = 1 million metric tons				
<u>Cost Category</u>	<u>Units</u>	<u>IC Engine</u>	<u>Combustion Turbine</u>	
POWER PROJECT COSTS				
Capital Costs (as-spent, 1996 online)				
Conversion system + collection system	\$/kW	2,000	2,423	
Conversion system only	\$/kW	1,283	1,691	
O&M Costs (1996)				
LFG collection system	c/kWh	1.2	1.2	(a)
Conversion system	c/kWh	1.8	1.5	(b)
Royalty Payments (1996)	c/kWh	0.5	0.5	(c)
FIRST YEAR COST OF ELECTRICITY (1996)				
Capital charge rate (project finance)		0.136	0.136	(d)
Total Electricity Cost				
Levelized capacity price	c/kWh	3.9	4.7	(e)
1996 O&M price	c/kWh	3.0	2.7	
Royalty Payment	c/kWh	0.5	0.5	
Total 1996 cost of electricity	c/kWh	7.4	7.9	
Incremental Electricity Cost				
Levelized capacity price	c/kWh	2.5	3.3	(f)
1996 O&M price	c/kWh	1.8	1.5	(e)
Royalty Payment	c/kWh	0.5	0.5	
Total 1996 cost of electricity	c/kWh	4.8	5.3	

Notes:

- (a) Based on EPA estimate for collection + flare systems (Exhibit 4-7), in \$1996. [EPA]
- (b) Based on O&M estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations—Technology and Economics," and in EPA Report to Congress (Exhibit 4-7).
- (c) Royalty payments to the landfill owner are estimated to be 10% of revenues (4.9 c/kWh).
- (d) Assumes: 20-year life, project finance with a 80/20 debt/equity ratio, 9% interest on debt; includes 15% return on equity; 10-year depreciation.
- (e) Calculated by multiplying capital \$/kW by CCR and dividing by annual hours of operation.
- (f) Conversion system only cost does not include capital and O&M costs associated with LFG collection system.

**TABLE A.4 ESTIMATED COST OF ELECTRICITY (1 million Mg case)
Municipal Bond Finance Case**

Example: Landfill waste in place = 1 million metric tons				
Cost Category	Units	IC Engine	Combustion Turbine	
POWER PROJECT COSTS				
Capital Costs (as-spent, 1996 online)				
Conversion system + collection system	\$/kW	2,000	2,423	
Conversion system only	\$/kW	1,283	1,691	
O&M Costs (1996)				
LFG collection system	c/kWh	1.2	1.2	(a)
Conversion system	c/kWh	1.8	1.5	(b)
Royalty Payments (1996)	c/kWh	0.5	0.5	(c)
FIRST YEAR COST OF ELECTRICITY (1996)				
Capital charge rate (muni bond finance)		0.111	0.111	(d)
Total Electricity Cost				
Levelized capacity price	c/kWh	3.2	3.8	(e)
1996 O&M price	c/kWh	3.0	2.7	
Royalty Payment	c/kWh	0.5	0.5	
Total 1996 cost of electricity	c/kWh	6.7	7.0	
Incremental Electricity Cost				
Levelized capacity price	c/kWh	2.0	2.7	(f)
1996 O&M price	c/kWh	1.8	1.5	(e)
Royalty Payment	c/kWh	0.5	0.5	
Total 1996 cost of electricity	c/kWh	4.3	4.7	

Notes:

- (a) Based on EPA estimate for collection + flare systems (Exhibit 4-7), in \$1996. [EPA]
- (b) Based on O&M estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations—Technology and Economics," and in EPA Report to Congress (Exhibit 4-7).
- (c) Royalty payments to the landfill owner are estimated to be 10% of revenues (4.9 c/kWh).
- (d) Assumes tax-exempt municipal bond financing at 6.5%.
- (e) Calculated by multiplying capital \$/kW by CCR and dividing by annual hours of operation.
- (f) Conversion system only cost does not include capital and O&M costs associated with LFG collection system.

TABLE A.5 ESTIMATED CAPITAL COSTS (5 million Mg case)

Example: Landfill waste in place = 5 million metric tons					
Cost Category	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
OPERATING DATA					
Net sustainable landfill gas production	mcf/day	2,988	2,988	2,988	(a)
Gross electric output	kW	5,188	5,188	7,324	(b)
Auxiliary and compressor loads	kW	254	461	561	(c)
Net electric output	kW	4,934	4,727	6,763	
On-line date		6/96	6/96	6/96	
Capacity factor (lifetime annual average)		80%	80%	80%	(d)
Annual full load operating hours	hours	7,008	7,008	7,008	
Annual electricity generated	kWh	34,577,472	33,126,816	47,395,104	
EQUIPMENT & INSTALLATION COSTS					
Energy Conversion System (\$1994)					
Engine, auxiliaries, construction	\$000	4,075	4,300	7,950	(e)
Interconnections (elec, water, LFG)	\$000	400	400	500	(f)
Gas compressor	\$000	250	750	750	
Energy conversion system cost	\$000	4,725	5,450	9,200	
LFG collection system cost (\$1994)	\$000	2,088	2,088	2,088	(g)
Engineering (\$1994) @ 5.0%	\$000	341	377	564	(h)
CAPITAL REQUIREMENT					
System cost (\$1994)	\$000	7,154	7,915	11,853	
Soft Costs					
Owners costs, escalation, interest		751	804	1,248	(i)
Contingency @ 5.0%		358	396	593	
Total Soft Costs	\$000	1,109	1,200	1,841	
Total Capital Requirement	\$000	8,263	9,115	13,694	
(as-spent dollars, 1996 on-line date)	\$/kW net	1,675	1,928	2,025	
Incremental Capital Requirement	\$000	5,807	6,659	11,216	(j)
(as-spent dollars, 1996 on-line date)	\$/kW net	1,177	1,409	1,658	

Notes:

- Based on landfill size of approximately 5 million metric tons. [EPA] (mcf = thousand cubic feet)
1 cf landfill gas = 0.5 cf methane
- $\text{kW} = (\text{cf/hr methane}) \times (1000 \text{ Btu/cf}) / (\text{generator Btu/kWh})$
- Compressor effects: IC engine -- 2% parasitic load; CTs -- 6% parasitic load
- Conservative estimated capacity factor over project life. [EPA]
- Includes prime mover, generator, plant auxiliaries, construction, LFG modifications, emissions controls.
- Assumed to be \$350,000 to \$450,000 for electric, \$50,000 for water.
- Calculated based on EPA Exhibit 4-7; includes collection system + flare. [EPA]
- Calculated as 5% of conversion and collection system costs.
- Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (12 - 18 mos) and interest during construction.
- Excludes capital and soft costs associated with the LFG collection system.

TABLE A.6 ESTIMATED COST OF ELECTRICITY (5 million Mg case)
Project Finance Case

Example: Landfill waste in place = 5 million metric tons					
Cost Category	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
POWER PROJECT COSTS					
Capital Costs (as-spent, 1996 online)					
Conversion system + collection system	\$/kW	1,675	1,928	2,025	
Conversion system only	\$/kW	1,177	1,409	1,658	
O&M Costs (1996)					
LFG collection system	c/kWh	0.5	0.5	0.5	(a)
Conversion system	c/kWh	1.8	1.5	1.6	(b)
Royalty Payments (1996)	c/kWh	0.5	0.5	0.5	(c)
FIRST YEAR COST OF ELECTRICITY (1996)					
Capital charge rate (project finance)		0.136	0.136	0.136	(d)
Total Electricity Cost					
Levelized capacity price	c/kWh	3.2	3.7	3.9	(e)
1996 O&M price	c/kWh	2.3	2.0	2.1	
Royalty payment	c/kWh	0.5	0.5	0.5	
Total 1996 cost of electricity	c/kWh	6.0	6.2	6.5	
Incremental Electricity Cost					
Levelized capacity price	c/kWh	2.3	2.7	3.2	(f)
1996 O&M price	c/kWh	1.8	1.5	1.6	(e)
Royalty payment	c/kWh	0.5	0.5	0.5	
Total 1996 cost of electricity	c/kWh	4.6	4.7	5.3	

Notes:

- (a) Based on EPA estimate for collection + flare systems (Exhibit 4-7), in \$1996. [EPA]
- (b) Based on O&M estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations—Technology and Economics," and in EPA Report to Congress (Exhibit 4-7).
- (c) Royalty payments to the landfill owner are estimated to be 10% of revenues (4.9 c/kWh).
- (d) Assumes: 20-year life, project finance with a 80/20 debt/equity ratio, 9% interest on debt; includes 15% return on equity; 10-year depreciation.
- (e) Calculated by multiplying capital \$/kW by CCR and dividing by annual hours of operation.
- (f) Incremental Electricity Cost does not include capital and O&M costs associated with LFG collection system.

TABLE A.7 ESTIMATED COST OF ELECTRICITY (5 million Mg case)
Municipal Bond Finance Case

Example: Landfill waste in place = 5 million metric tons				
Cost Category	Units	IC Engine	Combustion Turbine	Combined Cycle CT
POWER PROJECT COSTS				
Capital Costs (as-spent, 1996 online)				
Conversion system + collection system	\$/kW	1,675	1,929	2,025
Conversion system only (incremental)	\$/kW	1,177	1,409	1,658
O&M Costs (1996)				
LFG collection system	c/kWh	0.5	0.5	0.5 (a)
Electric generation system	c/kWh	1.8	1.5	1.6 (b)
Royalty Payments (1996)	c/kWh	0.5	0.5	0.5 (c)
FIRST YEAR COST OF ELECTRICITY (1996)				
Capital charge rate (muni bond finance)		0.111	0.111	0.111 (d)
Total Electricity Cost				
Levelized capacity price	c/kWh	2.7	3.1	3.2 (e)
1996 O&M price	c/kWh	2.3	2.0	2.1
Royalty payment	c/kWh	0.5	0.5	0.5
Total 1996 cost of electricity	c/kWh	5.5	5.6	5.8
Incremental Electricity Cost				
Levelized capacity price	c/kWh	1.9	2.2	2.6 (f)
1996 O&M price	c/kWh	1.8	1.5	1.6 (e)
Royalty payment	c/kWh	0.5	0.5	0.5
Total 1996 cost of electricity	c/kWh	4.2	4.2	4.7

Notes:

- (a) Based on EPA estimate for collection + flare systems (Exhibit 4-7), in \$1996. [EPA]
- (b) Based on O&M estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations—Technology and Economics," and in EPA Report to Congress (Exhibit 4-7).
- (c) Royalty payments to the landfill owner are estimated to be 10% of revenues (4.9 c/kWh).
- (d) Assumes tax-exempt municipal bond financing at 6.5%.
- (e) Calculated by multiplying capital \$/kW by CCR and dividing by annual hours of operation.
- (f) Incremental Electricity Cost does not include capital and O&M costs associated with LFG collection system.

TABLE A.8 ESTIMATED CAPITAL COSTS (10 million Mg case)

Example: Landfill waste in place = 10 million metric tons				
Cost Category	Units	IC Engine	Combustion Turbine	Combined Cycle CT
OPERATING DATA				
Net sustainable landfill gas production	mcf/day	5,266	5,266	5,266 (a)
Gross electric output	kW	9,142	9,142	12,907 (b)
Auxiliary and compressor loads	kW	433	799	899 (c)
Net electric output	kW	8,709	8,344	12,008
On-line date		6/96	6/96	6/96
Capacity factor (lifetime annual average)		80%	80%	80% (d)
Annual full load operating hours	hours	7,008	7,008	7,008
Annual electricity generated	kWh	61,032,672	58,474,752	84,152,064
EQUIPMENT & INSTALLATION COSTS				
Energy Conversion System (\$1994)				
Engine, auxiliaries, construction	\$000	7,200	7,350	13,100 (e)
Interconnections (elec, water, LFG)	\$000	400	400	500 (f)
Gas compressor	\$000	400	900	900
Energy conversion system cost	\$000	8,000	8,650	14,500
LFG collection system cost (\$1994)	\$000	3,599	3,599	3,599 (g)
Engineering (\$1994) @ 5.0%	\$000	580	612	905 (h)
CAPITAL REQUIREMENT				
System cost (\$1994)	\$000	12,179	12,861	19,004
Soft Costs				
Owners costs, escalation, interest		1,103	1,150	1,820 (i)
Contingency @ 5.0%		609	643	950
Total Soft Costs	\$000	1,711	1,793	2,770
Total Capital Requirement	\$000	13,890	14,654	21,774
(as-spent dollars, 1996 on-line date)	\$/kW net	1,595	1,756	1,813
Incremental Capital Requirement	\$000	9,658	10,422	17,504 (j)
(as-spent dollars, 1996 on-line date)	\$/kW net	1,109	1,249	1,458

Notes:

- (a) Based on landfill size of approximately 5 million metric tons. [EPA] (mcf = thousand cubic feet)
1 cf landfill gas = 0.5 cf methane
- (b) Calculated according to EPA formula: $kW = (cf/hr \text{ methane}) \times (1000 \text{ Btu/cf}) / \text{generator Btu/kWh}$
- (c) Compressor effects: IC engine -- 2% parasitic load; CTs -- 6% parasitic load
- (d) Conservative estimated capacity factor over project life. [EPA]
- (e) Includes prime mover, generator, plant auxiliaries, construction, LFG modifications, emissions controls.
- (f) Assumed to be \$350,000 to \$450,000 for electric, \$50,000 for water.
- (g) Calculated based on EPA Exhibit 4-7; includes collection system + flare. [EPA]
- (h) Calculated as 5% of conversion and collection system costs.
- (i) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (18 mos) and interest during construction.
- (j) Excludes capital and soft costs associated with the LFG collection system.

TABLE A.9 ESTIMATED COST OF ELECTRICITY (10 million Mg case)
Project Finance Case

Example: Landfill waste in place = 10 million metric tons				
Cost Category	Units	IC Engine	Combustion Turbine	Combined Cycle CT
POWER PROJECT COSTS				
Capital Costs (as-spent, 1996 online)				
Conversion system + collection system	\$/kW	1,595	1,756	1,813
Conversion system only	\$/kW	1,109	1,249	1,458
O&M Costs (1996)				
LFG collection system	c/kWh	0.4	0.4	0.4 (a)
Conversion system	c/kWh	1.8	1.3	1.5 (b)
Royalty Payments (1996)	c/kWh	0.5	0.5	0.5 (c)
FIRST YEAR COST OF ELECTRICITY (1996)				
Capital charge rate (project finance)		0.136	0.136	0.136 (d)
Total Electricity Cost				
Levelized capacity price	c/kWh	3.1	3.4	3.5 (e)
1996 O&M price	c/kWh	2.2	1.7	1.9
Royalty Payment	c/kWh	0.5	0.5	0.5
Total 1996 cost of electricity	c/kWh	5.8	5.6	5.9
Incremental Electricity Cost				
Levelized capacity price	c/kWh	2.2	2.4	2.8 (f)
1996 O&M price	c/kWh	1.8	1.3	1.5 (e)
Royalty Payment	c/kWh	0.5	0.5	0.5
Total 1996 cost of electricity	c/kWh	4.5	4.2	4.8

Notes:

- (a) Based on EPA estimate for collection + flare systems (Exhibit 4-7), in \$1996. [EPA]
- (b) Based on O&M estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations—Technology and Economics," and in EPA Report to Congress (Exhibit 4-7).
- (c) Royalty payments to the landfill owner are estimated to be 10% of revenues (4.9 c/kWh).
- (d) Assumes: 20-year life, project finance with a 80/20 debt/equity ratio, 9% interest on debt; includes 15% return on equity; 10-year depreciation.
- (e) Calculated by multiplying capital \$/kW by CCR and dividing by annual hours of operation.
- (f) Conversion system only cost does not include capital and O&M costs associated with LFG collection system.

**TABLE A.10 ESTIMATED COST OF ELECTRICITY (10 million Mg case)
Municipal Bond Finance Case**

Example: Landfill waste in place = 10 million metric tons					
<u>Cost Category</u>	<u>Units</u>	<u>IC Engine</u>	<u>Combustion Turbine</u>	<u>Combined Cycle CT</u>	
POWER PROJECT COSTS					
Capital Costs (as-spent, 1996 online)					
Conversion system + collection system	\$/kW	1,595	1,756	1,813	
Conversion system only	\$/kW	1,109	1,249	1,458	
O&M Costs (1996)					
LFG collection system	c/kWh	0.4	0.4	0.4	(a)
Conversion system	c/kWh	1.8	1.3	1.5	(b)
Royalty Payments (1996)	c/kWh	0.5	0.5	0.5	(c)
FIRST YEAR COST OF ELECTRICITY (1996)					
Capital charge rate (muni bond finance)		0.111	0.111	0.111	(d)
Total Electricity Cost					
Levelized capacity price	c/kWh	2.5	2.8	2.9	(e)
1996 O&M price	c/kWh	2.2	1.7	1.9	
Royalty Payment	c/kWh	0.5	0.5	0.5	
Total 1996 cost of electricity	c/kWh	5.2	5.0	5.3	
Incremental Electricity Cost					
Levelized capacity price	c/kWh	1.8	2.0	2.3	(f)
1996 O&M price	c/kWh	1.8	1.3	1.5	(e)
Royalty Payment	c/kWh	0.5	0.5	0.5	
Total 1996 cost of electricity	c/kWh	4.1	3.8	4.3	

Notes:

- (a) Based on EPA estimate for collection + flare systems (Exhibit 4-7), in \$1996. [EPA]
- (b) Based on O&M estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations—Technology and Economics," and in EPA Report to Congress (Exhibit 4-7).
- (c) Royalty payments to the landfill owner are estimated to be 10% of revenues (4.9 c/kWh).
- (d) Assumes tax-exempt municipal bond financing at 6.5%.
- (e) Calculated by multiplying capital \$/kW by CCR and dividing by annual hours of operation.
- (f) Conversion system only cost does not include capital and O&M costs associated with LFG collection system.

TABLE A.11 COMPARISON OF PROJECT REVENUES & EXPENSES
(1 st Year)

Example: Landfill waste in place = 5 million metric tons				
	<u>Units</u>	<u>IC Engine</u>	<u>Combustion</u>	<u>Combined</u>
	<u>c/kWh</u>	<u>4.9</u>	<u>Turbine</u>	<u>Cycle CT</u>
		4.9	4.9	4.9
Revenues				
PROJECT FINANCE CASE				
Expenses (including Owner's Return)				
Total	c/kWh	6.0	6.2	6.5
Incremental	c/kWh	4.6	4.7	5.3
Revenues Minus Expenses				
Total	c/kWh	(1.1)	(1.3)	(1.6)
Incremental	c/kWh	0.3	0.2	(0.4)
1996 Tax Credit	c/kWh	1.3	1.3	0.9
Estimated Surplus (Shortfall) Cash Flow After Taxes and Owner's Return				
Total Cost Basis	c/kWh	0.2	0.0	(0.7)
	\$000	\$69	\$0	(\$332)
Incremental Cost Basis	c/kWh	1.6	1.5	0.5
	\$000	\$553	\$497	\$237
MUNICIPAL BOND FINANCE CASE				
Expenses (including financing costs)				
Total	c/kWh	5.0	5.1	5.3
Incremental	c/kWh	3.7	3.7	4.2
Revenues Minus Expenses				
Total	c/kWh	(0.1)	(0.2)	(0.4)
Incremental	c/kWh	1.2	1.2	0.7
1996 REPI Subsidy	c/kWh	0.0	0.0	0.0
Estimated Surplus (Shortfall) Cash Flow After Taxes and Financing Expenses				
Total Cost Basis	c/kWh	(0.1)	(0.2)	(0.4)
	\$000	(\$35)	(\$66)	(\$190)
Incremental Cost Basis	c/kWh	1.2	1.2	0.7
	\$000	\$415	\$398	\$332

Notes:

See Tables A.12–A.14 for notes on calculations.

TABLE A.12 EXAMPLE POWER PROJECT REVENUES (1st Year)

Example: Landfill waste in place = 5 million metric tons					
	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
PROJECT OPERATING DATA					
Net sustainable landfill gas production	mcf/day	2,988	2,988	2,988	(a)
Gross electric output	kW	5,188	5,188	7,324	
Net electric output	kW	4,934	4,727	6,763	
Annual electricity generated	kWh	34,577,472	33,126,816	47,395,104	
Electricity used on-site	kWh	3,000,000	3,000,000	3,000,000	(b)
Net electricity sold to utility	kWh	31,577,472	30,126,816	44,395,104	
ANNUAL REVENUES					
Electricity Sales to Utility in 1st Year	\$000	\$1,522	\$1,452	\$2,140	(c)
Electricity Sales On-Site in 1st Year	\$000	\$177	\$177	\$177	(d)
Total Annual Revenues	\$000	\$1,699	\$1,629	\$2,317	
REVENUES ON PER kWh BASIS	c/kWh	4.9	4.9	4.9	(e)

Notes:

- (a) Calculated using statistical model 4.2 in EPA Report to Congress. [EPA] The resulting methane production estimate is within the range predicted by the models presented in Part I.
- (b) Assumed for example purposes.
- (c) Product of utility sales kWh and assumed 1996 buyback electricity rate of 4.8 c/kWh.
- (d) Product of on-site sales kWh and assumed 1996 retail electricity rate of 5.9 c/kWh.
- (e) Total annual revenues divided by total kWh generated.

TABLE A.13 COMPARISON OF PROJECT REVENUES & EXPENSES
(1 st Year)
Project Finance Case

Example: Landfill waste in place = 5 million metric tons					
	<u>Units</u>	<u>IC Engine</u>	<u>Combustion Turbine</u>	<u>Combined Cycle CT</u>	
REVENUES	c/kWh	4.9	4.9	4.9	(a)
EXPENSES (including Owner's Return)					(b)
Total	c/kWh	6.0	6.2	6.5	
Incremental	c/kWh	4.6	4.7	5.3	
REVENUES MINUS EXPENSES					
Total	c/kWh	(1.1)	(1.3)	(1.6)	
Incremental	c/kWh	0.3	0.2	(0.4)	
1996 TAX CREDIT					
	\$/MMBtu	1.049	1.049	1.049	(c)
	c/kWh	1.3	1.3	0.9	(d)
ESTIMATED SURPLUS (SHORTFALL) CASH AFTER TAXES & OWNER'S RETURN					(e)
Total Cost Basis	c/kWh	0.2	0.0	(0.7)	
	\$000	\$69	\$0	(\$332)	(f)
Incremental Cost Basis	c/kWh	1.6	1.5	0.5	
	\$000	\$553	\$497	\$237	

Notes:

- (a) Calculated in Table A.12
- (b) Calculated in Table A.6. Income taxes, property taxes, and owner's 15% return on equity are included in these expenses.
- (c) Based on a tax credit of \$0.979/MMBtu (\$1994) escalated for 2 years @ 3.5%. [PUR]
If only 60% of tax credit is applied to project, credit drops by about 0.5 c/kWh, or about \$173,000.
- (d) Calculated by multiplying by an electric heat rate of 12.0 MMBtu/MWh for the IC and CT,
and by 8.5 MMBtu/MWh for the combined cycle CT.
- (e) Estimated Income is net of income taxes, property taxes, administrative expenses, and owner's 15% return on equity. A negative value indicates that first-year cash flow does not cover the owner's desired 15% return. It is assumed that the project/owner has sufficient tax liability to be able to take full advantage of the tax credit. In many cases, only about 60% of the tax credit can be used.

TABLE A.14 COMPARISON OF PROJECT REVENUES & EXPENSES
(1 st Year)
Municipal Bond Finance Case

Example: Landfill waste in place = 5 million metric tons				
	<u>Units</u>	<u>IC Engine</u>	<u>Combustion Turbine</u>	<u>Combined Cycle CT</u>
REVENUES	c/kWh	4.9	4.9	4.9
				(a)
EXPENSES				(b)
Total	c/kWh	5.0	5.1	5.3
Incremental	c/kWh	3.7	3.7	4.2
REVENUES MINUS EXPENSES				
Total	c/kWh	(0.1)	(0.2)	(0.4)
Incremental	c/kWh	1.2	1.2	0.7
1996 REPI SUBSIDY	c/kWh	0.0	0.0	0.0
ESTIMATED SURPLUS (SHORTFALL) CASH AFTER TAXES & FINANCING EXPENSES				
Total Cost Basis	c/kWh	(0.1)	(0.2)	(0.4)
	\$000	(\$35)	(\$66)	(\$190)
				(c)
Incremental Cost Basis	c/kWh	1.2	1.2	0.7
	\$000	\$415	\$398	\$332

Notes:

- (a) Calculated in Table A.12
- (b) Expenses include the financing costs associated with issuing tax-exempt municipal bonds with a 6.5% interest rate (see Table A.7)
- (c) Estimated Income is net of property taxes, administrative expenses, and bond financing expenses. A positive value indicates that first-year cash flow exceeds expenses, including the bond debt service expenses.

TABLE A.15 ESTIMATED MEDIUM-BTU PROJECT CAPITAL COSTS
(1 million Mg case)

Example: Landfill waste in place = 1 million metric tons			
Cost Category	Units	Baseload user (continuous)	Heat load user (seasonal)
OPERATING DATA			
Net sustainable landfill gas production	mcf/day	642	642 (a)
Net fuel output (MMBtu)	MMBtu/day	321	321 (b)
On-line date		6/96	6/96
Capacity factor (lifetime annual average)		90%	40% (c)
Annual full load operating hours	hours	7,884	3,504
Annual volume of gas sold	MMBtu	105,488	46,884
EQUIPMENT & INSTALLATION COSTS			
Gas Delivery System (\$1994)			
Condensate removal/filtration	\$000	8	8 (d)
Compressor/Blower station	\$000	75	75 (e)
Pipeline interconnect	\$000	350	350 (f)
Fuel burning equipment conversion	\$000	150	150 (g)
Gas delivery system cost (\$1994)		583	583
LFG collection system cost (\$1994)	\$000	628	628 (h)
Engineering (\$1994)	\$000	61	61 (i)
CAPITAL REQUIREMENT			
System cost (\$1994)	\$000	1,271	1,271
System cost (\$1996)	\$000	1,362	1,362
Soft costs (\$1996)			
Owners costs, escalation, interest		85	85 (j)
Contingency @5.0%		68	68
Total Soft Costs	\$000	153	153
Total Capital Requirement (as-spent dollars, 1996 on-line date)	\$000	1,515	1,515
Incremental Capital Requirement	\$000	729	729 (k)

Notes:

- (a) Based on landfill size of approximately 1 metric ton.[EPA]
- (b) Assumes landfill gas has 500 Btu/cf, or 1 cf landfill gas = 0.5 cf methane.
- (c) Assumes baseload user has a year-round need for gas, and heat load user only uses gas in the five winter months.
- (d) Based on an estimate obtained from Perry Equipment for liquid and solid filtration system.
- (e) Based on estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations - Technology and Economics", and in Augenstein and Pacey, "Landfill Gas Energy Utilization: Technology Options and Case Studies"
- (f) Based on the cost of a one mile pipeline (pipeline costs can range from \$250,000 to \$500,000 per mile).
- (g) Based on the cost of retrofitting one boiler.[PTI]
- (h) Calculated based on EPA Exhibit 4-7; includes collection system + flare. [EPA]
- (i) Calculated as 5% of conversion and collection costs.
- (j) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (6 months) and interest during construction.
- (k) Excludes capital and soft costs associated with the LFG collection system.

TABLE A.16 ESTIMATED COST OF MEDIUM-BTU GAS (1M Mg case)

Example: Landfill waste in place = 1 million metric tons			
Cost Category	Units	Baseload user (continuous)	Heat load user (seasonal)
GAS PRODUCTION COSTS			
Capital Costs (as-spent, 1996 online)			(a)
Total capital requirement	\$/MMBtu	14.36	32.31
Incremental capital requirement	\$/MMBtu	6.91	15.56
O&M Costs (1996)			
LFG collection system	\$/MMBtu	0.84	1.89 (b)
Gas delivery system	\$/MMBtu	0.11	0.26 (c)
Tax Credit (1996)	\$/MMBtu	1.049	1.049 (d, h)
FIRST YEAR COST OF GAS (1996)			
Capital charge rate		0.136	0.136 (e)
Total Gas Cost			
Levelized capacity price	\$/MMBtu	1.95	4.39 (f)
1996 O&M price	\$/MMBtu	0.95	2.14
Total 1996 cost of gas	\$/MMBtu	2.91	6.54
Cost of gas including tax credit	\$/MMBtu	1.86	5.49
Incremental Gas Cost			
Levelized capacity price	\$/MMBtu	0.94	2.12 (g)
1996 O&M price	\$/MMBtu	0.11	0.26
Total 1996 cost of gas	\$/MMBtu	1.05	2.37
Cost of gas including tax credit	\$/MMBtu	0.01	1.32

Notes:

- (a) Assumes annual gas sales of 105,488 MMBtu to baseload user and 46,884 MMBtu to heat load user.
- (b) Based on EPA estimate for collection + flare systems (Exhibit 4-7), escalated to \$1996. [EPA]
- (c) Based on pipeline delineation costs and minor filtration system maintenance costs. [Augenstein and Pacey]
- (d) Based on a tax credit value of \$0.979/MMBtu (\$1994), escalated for 2 years. [PUR]
- (e) Assumes: 20-year life, project finance with a 80/20 debt/equity ratio, 9% interest on debt; includes 15% return on equity; 10-year depreciation
- (f) Calculated by multiplying capital \$/MMBtu by CCR.
- (g) Incremental Gas Cost does not include capital and O&M costs associated with LFG collection system.
- (h) Assumes total value of tax credit goes to the project. In some cases, only a percentage of the tax credit value will be credited to the project due to transaction costs associated with transferring the credits to a third party. For example, 60% of the tax credit may be realized by the project developer; therefore, the value of the tax credit would only be (60% * \$1.049), or \$0.63/MMBtu.

**TABLE A.17 ESTIMATED MEDIUM-BTU PROJECT CAPITAL COSTS
(5 million Mg case)**

Example: Landfill waste in place = 5 million metric tons			
Cost Category	Units	Baseload user (continuous)	Heat load user (seasonal)
OPERATING DATA			
Net sustainable landfill gas production	mcf/day	2,988	2,988 (a)
Net fuel output (MMBtu)	MMBtu/day	1,494	1,494 (b)
On-line date		6/96	6/96
Capacity factor (lifetime annual average)		90%	40% (c)
Annual full load operating hours	hours	7,884	3,504
Annual volume of gas sold	MMBtu	490,811	218,138
EQUIPMENT & INSTALLATION COSTS			
Gas Delivery System (\$1994)			
Condensate removal/filtration	\$000	15	15 (d)
Compressor/Blower station	\$000	100	100 (e)
Pipeline interconnect	\$000	350	350 (f)
Fuel burning equipment conversion	\$000	150	150 (g)
Gas delivery system cost (\$1994)		615	615
LFG collection system cost (\$1994)	\$000	2,098	2,098 (h)
Engineering (\$1994)	\$000	136	136 (i)
CAPITAL REQUIREMENT			
System cost (\$1994)	\$000	2,848	2,848
System cost (\$1996)	\$000	3,051	3,051
Soft costs(\$1996)			
Owners costs, escalation, interest		190	190 (j)
Contingency @5.0%		153	153
Total Soft Costs	\$000	343	343
Total Capital Requirement (as-spent dollars, 1996 on-line date)	\$000	3,394	3,394
Incremental Capital Requirement	\$000	769	769 (k)

Notes:

- (a) Based on landfill size of approximately 5 metric tons.[EPA]
- (b) Assumes landfill gas has 500 Btu/cf, or 1 cf landfill gas = 0.5 cf methane.
- (c) Assumes baseload user has a year-round need for gas, and heat load user only uses gas in the five winter months.
- (d) Based on an estimate obtained from Perry Equipment for liquid and solid filtration system.
- (e) Based on estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations - Technology and Economics", and in Augenstein and Pacey, "Landfill Gas Energy Utilization: Technology Options and Case Studies"
- (f) Based on the cost of a one mile pipeline (pipeline costs can range from \$250,000 to \$500,000 per mile).
- (g) Based on the cost of retrofitting one boiler.[PTI]
- (h) Calculated based on EPA Exhibit 4-7; includes collection system + flare. [EPA]
- (i) Calculated as 5% of conversion and collection costs.
- (j) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (6 months) and interest during construction.
- (k) Excludes capital and soft costs associated with the LFG collection system.

TABLE A.18 ESTIMATED COST OF MEDIUM-BTU GAS (5M Mg case)

Example: Landfill waste in place = 5 million metric tons			
Cost Category	Units	Baseload user (continuous)	Heat load user (seasonal)
GAS PRODUCTION COSTS			
Capital Costs (as-spent, 1996 online)			(a)
Total capital requirement	\$/MMBtu	6.92	15.56
Incremental capital requirement	\$/MMBtu	1.57	3.53
O&M Costs (1996)			
LFG collection system	\$/MMBtu	0.31	0.70 (b)
Gas delivery system	\$/MMBtu	0.02	0.06 (c)
Tax Credit (1996)	\$/MMBtu	1.049	1.049 (d, h)
FIRST YEAR COST OF GAS (1996)			
Capital charge rate		0.136	0.136 (e)
Total Gas Cost			
Levelized capacity price	\$/MMBtu	0.94	2.12 (f)
1996 O&M price	\$/MMBtu	0.34	0.75
Total 1996 cost of gas	\$/MMBtu	1.28	2.87
Cost of gas including tax credit	\$/MMBtu	0.23	1.82
Incremental Gas Cost			
Levelized capacity price	\$/MMBtu	0.21	0.48 (g)
1996 O&M price	\$/MMBtu	0.02	0.06
Total 1996 cost of gas	\$/MMBtu	0.24	0.53
Cost of gas including tax credit	\$/MMBtu	(0.81)	(0.51)

Notes:

- (a) Assumes annual gas sales to baseload user of 490,811 MMBtu and sales of 218,138 MMBtu to heat load user.
- (b) Based on EPA estimate for collection + flare systems (Exhibit 4-7), escalated to \$1996. [EPA]
- (c) Based on pipeline delineation costs and minor filtration system maintenance costs. [Augenstein and Pacey]
- (d) Based on a tax credit value of \$0.979/MMBtu (\$1994), escalated for 2 years. [PUR]
- (e) Assumes: 20-year life, project finance with a 80/20 debt/equity ratio, 9% interest on debt; includes 15% return on equity; 10-year depreciation
- (f) Calculated by multiplying capital \$/MMBtu by CCR.
- (g) Incremental Gas Cost does not include capital and O&M costs associated with LFG collection system.
- (h) Assumes total value of the tax credit goes to the project. In some cases, only a percentage of the tax credit value will be credited to the project due to transaction costs associated with transferring the credits to a third party. For example, 60% of the credit may be realized by the project developer; therefore, the value of the tax credit would only be (60% * \$1.049), or \$0.63/MMBtu.

**TABLE A.19 ESTIMATED MEDIUM-BTU PROJECT CAPITAL COSTS
(10 million Mg case)**

Example: Landfill waste in place = 10 million metric tons			
Cost Category	Units	Baseload user (continuous)	Heat load user (seasonal)
OPERATING DATA			
Net sustainable landfill gas production	mcf/day	5,266	5,266 (a)
Net fuel output (MMBtu)	MMBtu/day	2,633	2,633 (b)
On-line date		6/96	6/96
Capacity factor (lifetime annual average)		90%	40% (c)
Annual full load operating hours	hours	7,884	3,504
Annual volume of gas sold	MMBtu	864,917	384,408
EQUIPMENT & INSTALLATION COSTS			
Gas Delivery System (\$1994)			
Condensate removal/filtration	\$000	25	25 (d)
Compressor/Blower station	\$000	200	200 (e)
Pipeline interconnect	\$000	350	350 (f)
Fuel burning equipment conversion	\$000	150	150 (g)
Gas delivery system cost (\$1994)		725	725
LFG collection system cost (\$1994)	\$000	3,599	3,599 (h)
Engineering (\$1994)	\$000	216	216 (i)
CAPITAL REQUIREMENT			
System cost (\$1994)	\$000	4,540	4,540
System cost (\$1996)	\$000	4,863	4,863
Soft costs(\$1996)			
Owners costs, escalation, interest		303	303 (j)
Contingency @5.0%		243	243
Total Soft Costs	\$000	546	546
Total Capital Requirement (as-spent dollars, 1996 on-line date)	\$000	5,410	5,410
Incremental Capital Requirement	\$000	907	907 (k)

Notes:

- (a) Based on landfill size of approximately 10 metric tons.[EPA]
- (b) Assumes landfill gas has 500 Btu/cf, or 1 cf landfill gas = 0.5 cf methane.
- (c) Assumes baseload user has a year-round need for gas, and heat load user only uses gas in the five winter months.
- (d) Based on an estimate obtained from Perry Equipment for liquid and solid filtration system.
- (e) Based on estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations -- Technology and Economics", and in Augenstein and Pacey, "Landfill Gas Energy Utilization: Technology Options and Case Studies"
- (f) Based on the cost of a one mile pipeline (pipeline costs can range from \$250,000 to \$500,000 per mile).
- (g) Based on the cost of retrofitting one boiler.[PTI]
- (h) Calculated based on EPA Exhibit 4-7; includes collection system + flare. [EPA]
- (i) Calculated as 5% of conversion and collection costs.
- (j) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (6 months) and interest during construction.
- (k) Excludes capital and soft costs associated with the LFG collection system.

TABLE A.20 ESTIMATED COST OF MEDIUM-BTU GAS (10M Mg case)

Example: Landfill waste in place = 10 million metric tons			
Cost Category	Units	Baseload user (continuous)	Heat load user (seasonal)
GAS PRODUCTION COSTS			
Capital Costs (as-spent, 1996 online)			(a)
Total capital requirement	\$/MMBtu	6.25	14.07
Incremental capital requirement	\$/MMBtu	1.05	2.36
O&M Costs (1996)			
LFG collection system	\$/MMBtu	0.25	0.57 (b)
Gas delivery system	\$/MMBtu	0.01	0.03 (c)
Tax Credit (1996)	\$/MMBtu	1.049	1.049 (d, h)
FIRST YEAR COST OF GAS (1996)			
Capital charge rate		0.136	0.136 (e)
Total Gas Cost			
Levelized capacity price	\$/MMBtu	0.85	1.91 (f)
1996 O&M price	\$/MMBtu	0.27	0.60
Total 1996 cost of gas	\$/MMBtu	1.12	2.51
Cost of gas including tax credit	\$/MMBtu	0.07	1.46
Incremental Gas Cost			
Levelized capacity price	\$/MMBtu	0.14	0.32 (g)
1996 O&M price	\$/MMBtu	0.01	0.03
Total 1996 cost of gas	\$/MMBtu	0.16	0.35
Cost of gas including tax credit	\$/MMBtu	(0.89)	(0.70)

Notes:

- (a) Assumes annual gas sales to baseload user of 864,917 MMBtu and sales of 384,408 MMBtu to heat load user.
- (b) Based on EPA estimate for collection + flare systems (Exhibit 4-7), escalated to \$1996. [EPA]
- (c) Based on pipeline delineation costs and minor filtration system maintenance costs. [Augenstein and Pacey]
- (d) Based on a tax credit value of \$0.979/MMBtu (\$1994), escalated for 2 years. [PUR]
- (e) Assumes: 20-year life, project finance with a 80/20 debt/equity ratio, 9% interest on debt; includes 15% return on equity; 10-year depreciation
- (f) Calculated by multiplying capital \$/MMBtu by CCR.
- (g) Incremental Gas Cost does not include capital and O&M costs associated with LFG collection system.
- (h) Assumes total value of tax credit goes to the project. In some cases, only a percentage of the tax credit value will be credited to the project due to transaction costs associated with transferring the credits to a third party. For example, 60% of the credit may be realized by the project developer; therefore, the value of the tax credit would only be (60% * \$1.049), or \$0.63/MMBtu.

APPENDIX B
LIST OF U.S. EPA OFFICES

U.S. Environmental Protection Agency Offices

EPA Region	EPA Address	States Included in Region	Regional Contact	Phone	Fax
	Landfill Methane Program 401 M St., SW, 6202J Washington, DC 20460	All		202-233-9042	
1	John F. Kennedy Federal Bldg. One Congress Street Boston, MA 02203	CT, ME, MA, NH, RI, VT	Jeanne Cosgrove	617-565-9451	617-565-4940
2	Federal Office Bldg. 26 Federal Plaza New York, NY 10278	NJ, NY, Puerto Rico, Virgin Islands	Christine DeRosa	212-637-4022	212-637-3998
3	Curtis Building Sixth and Walnut Streets Philadelphia, PA 19106	DE, DC, MD, PA, VA, WV	Jim Topsale	215-566-2190	215-566-2124
4	345 Courtland, NE Atlanta, GA 30308	AL, FL, GA, MS, KY, NC, SC, TN	Scott Davis	404-347-5014 Ext. 4144	404-347-3059
5	230 South Dearborn St. Chicago, IL 60604	IL, MN, MI, OH, IN, WI	Charles Hatten	312-886-6031	312-886-5824
6	First International Bldg. 1202 Elm Street Dallas, TX 75270	AR, LA, NM, OK, TX	Mick Cote	214-665-7219	214-665-2164
7	324 E. Eleventh Street Kansas City, MO 64106	IA, KS, MI, NE	Ward Burns	913-551-7960	913-551-7065

EPA Region	EPA Address	States Included in Region	Regional Contact	Phone	Fax
8	1860 Lincoln Street Denver, CO 80295	CO, MN, ND, SD, UT, WY	John Dale	303-312-6934	303-312-6064
9	215 Freemont Street San Francisco, CA 94105	AZ, CA, HI, NV, Guam, American Samoa	Patricia Bowlin	415-744-1188	415-744-1076
10	1200 Sixth Avenue Seattle, WA 98101	WA, OR, ID, AK	John Keenan	206-553-1817	206-553-0110

APPENDIX C

EXECUTIVE SUMMARY OF A POWER PURCHASE AGREEMENT

EXECUTIVE SUMMARY
OF
PURCHASED POWER AGREEMENT

Supplier Name

This Executive Summary describes the principal terms and conditions of an agreement (the "Agreement") between Duke Power Company ("Duke") and the owner/operator ("Supplier") of an electric generating facility which is a qualified facility ("QF") under the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). In the event of an inconsistency or conflict between the Agreement and this Executive Summary the terms of the Agreement shall apply.

ARTICLE 1 (Service Requirements) sets forth basic information about Supplier's facility (the "Facility") including, among other things, its nameplate capacity, location of the delivery point where Supplier will deliver energy to Duke, and the Supplier's "Capacity Commitment" (the average capacity in kilowatts Supplier commits to deliver to Duke during On-Peak Hours). Articles 1.6 and 1.7 set forth metering and fuel cost information requirements. Article 1.9 states that back-up and maintenance power for the Facility's auxiliary electrical requirements shall be purchased from Duke pursuant to a separate electric service agreement on an appropriate rate schedule.

ARTICLE 2 (Service Regulations and Regulatory Approval) states that the Agreement is contingent upon the Supplier obtaining and maintaining approval from all applicable regulatory bodies. Article 2.2 states that the provisions of the Agreement are subject to review by the North Carolina Utilities Commission (the "Commission"), and Article 2.3 provides that the sale, delivery, receipt and use of electric power under the Agreement is governed by Duke's Service Regulations as filed with the Commission, and that changes to said regulations upon order of the Commission, which changes are in conflict with the provisions of this Agreement, shall control over such provisions. However, Article 2.4 states that to the extent this Agreement is explicitly approved by an order of the Commission, Article 2.2 shall not apply, and the Agreement shall control over any changes to the Service Regulations except those which relate to extra facilities and metering. Article 2.5 states that whether or not the Agreement is explicitly approved by the Commission, it is thereafter subject to review in a general rate case or by complaint proceeding.

According to ARTICLE 3 (Term), the term of the Agreement begins on the date of execution and shall continue for _____ years from the Commercial Operations Date, which is defined in Article 3.4 as the date of the first regular meter reading following receipt by Duke of written notice from the Supplier declaring the Facility to be in Commercial Operation, after the Facility has passed

1 acceptance testing. The Anticipated Commercial Operations Date is _____, 199__
2 but Supplier may revise the Anticipated Commercial Operations Date one time during the first six
3 months following execution of the Agreement, to a date not later than twelve months after the
4 originally specified date.

5
6 Article 3.2 provides that the Supplier shall notify Duke of the date of the commencement of
7 construction of the Facility, commencement of construction being defined therein.

8
9 Article 3.3 provides that the Initial Delivery Date shall be the first date upon which energy is
10 generated by the Facility and delivered to and metered by Duke. The Anticipated Initial Delivery
11 Date is _____. The Supplier may change the Anticipated Initial Delivery Date on
12 written notice to Duke at least one year prior to the revised date, but in no event may the Initial
13 Delivery Date be earlier than _____.

14
15 Article 3.5 sets forth a procedure to determine the disposition of power produced by the plant after
16 the expiration of this Agreement. Between 45 and 60 months prior to the expiration of this
17 Agreement, Supplier must notify Duke as to whether it wishes to continue to generate electricity
18 at the Facility. If it does, Duke must then, within six months of Supplier's notice, respond by
19 notifying Supplier as to whether Duke wishes to continue to purchase energy and capacity. If Duke
20 does wish to continue such purchases, the parties will then enter into good-faith negotiations to
21 conclude a new purchased power agreement. The rates for the new agreement will be determined
22 based upon Duke's then-current projections of avoided capacity and energy costs and other
23 relevant factors. If Duke notifies Supplier that it does not wish to continue to purchase energy and
24 capacity, or if the parties cannot reach a new agreement, then they are to negotiate the disposition
25 of power to be generated at the Facility, provided that Duke is not to be obligated to transmit
26 power from the Facility directly to any ultimate consumers of electricity.

27
28 ARTICLE 4 (Rate Schedule) provides that energy and capacity payments to the Supplier will be
29 determined using the rates or rate formulas set forth in Appendix A, applying the energy credit
30 rates to the KWH delivered to Duke during the On-Peak Hours and Off-Peak Hours (as defined
31 therein) of each month, and applying the capacity credit rates to the KWH delivered to Duke
32 during the On-Peak Hours of each month, up to a maximum of 110 percent of the then-applicable
33 Capacity Commitment. Article 4.6 sets forth a mechanism for adjusting the energy in the event
34 the average monthly power factor is less than 90 percent or greater than 97 percent.

35
36 Article 4.7 provides that payments to be made to the Supplier are conditioned on recovery by Duke
37 of all of said payments from its customers. If Duke is denied such recovery, Duke may reduce

1 payments to Supplier to the highest level allowed by the Commission or other regulatory body.
2 If Duke initially recovers payments, but recovery is subsequently disallowed and charged back to
3 Duke, Duke may offset subsequent payments due from Duke to Supplier, or may require
4 repayment by Supplier.

5
6 ARTICLE 5 (Capacity Commitment) states that Supplier shall operate its generating facilities so
7 as to meet its Capacity Commitment as designated in Article 1.5(b) in each On-Peak Month.
8 Article 5.1(a)-(d) sets forth the definitions of "Capacity Commitment"; "Average On-Peak
9 Capacity"; "Monthly Capacity Ratio" and "Annual Capacity Ratio" and the methodologies for
10 calculating them. Article 5.1(e) states that reductions in capacity resulting from Service
11 Interruptions (as defined in Article 8), changes in steam sales requirements or for reasons other
12 than Force Majeure that occur during the On-Peak Hours of the On-Peak Months are not
13 excluded from the calculations of the Average On-Peak Capacity and the Capacity Ratios. Article
14 5.1(f) sets forth the circumstances under which On-Peak Months during which performance has
15 been affected by conditions or events of Force Majeure shall be excluded from or included in the
16 calculation of the Annual Capacity Ratio.

17
18 Article 5.2 states that when the Annual Capacity Ratio is less than 90 percent for two consecutive
19 months, the Capacity Commitment will automatically be reduced. The revised Capacity
20 Commitment is calculated by multiplying the previous Capacity Commitment by the Annual
21 Capacity Ratio existing at the end of the two-month period. In the event of an automatic Capacity
22 Commitment reduction, pursuant to Article 5.2(a), or an agreed-upon Capacity Commitment
23 reduction pursuant to Article 5.2(b), the costs and damages provisions of Paragraph 11.1 shall
24 apply, according to Article 5.4.

25
26 ARTICLE 6 (Interconnection Facilities) states that Duke will furnish, own and maintain
27 appropriate interconnection facilities in order to serve the Supplier. Supplier shall, upon
28 completion of installation of the Interconnection Facilities, pay a monthly charge totaling, as a
29 preliminary estimate, \$ _____, which is 1.7 percent of the installed cost. The final costs
30 and charges shall be calculated no earlier than 12 months prior to the installation of the
31 Interconnection Facilities. Duke reserves the right to install additional facilities, and to adjust the
32 Interconnection Facilities Charge for such additional facilities or to reflect Commission-approved
33 changes in the Extra Facilities provisions of Duke's Service Regulations.

34
35 ARTICLE 7 (Payments) sets forth billing and payment procedures. Duke reserves the right to set
36 off any amounts due to it from Supplier against any amounts due from Duke to Supplier.
37

ARTICLE 8 (Service Interruptions) states that, while the parties shall use reasonable diligence to provide satisfactory service, they do not guarantee continuous service. Article 8.2 lists conditions or events which are defined as "Service Interruptions." Pursuant to Article 8.3, neither party shall be liable for any loss or damage resulting from Service Interruptions, except that Supplier shall be liable to Duke for costs and damages as set forth in Article 11.1 if the occurrence of Service Interruptions results in a capacity reduction.

ARTICLE 9 (Force Majeure) defines certain circumstances which are "beyond the reasonable control" of the parties as "conditions or events of Force Majeure", and also lists certain events and circumstances which are excluded from that definition. Pursuant to Article 9.3, if certain conditions are met, then the parties are not responsible for any delay or failure of performance due solely to force majeure (except for the requirement for Supplier to begin commercial operation as set forth in Article 3.4). However, notwithstanding Article 9.3, Article 9.4 states that such failures of performance may be excused by force majeure for periods of no longer than one year and not beyond the term of the Agreement. Thus, delays or failures of performance, even if excused by force majeure, become defaults one year from the date that the affected party notifies the other party of the condition or event of Force Majeure. At such time, the other party may terminate the Agreement or may, in its sole discretion, extend the period for which the delay or failure in performance is excused. If, under such circumstances, Duke does not terminate the Agreement, and the condition or event of Force Majeure results in a capacity reduction, then the provisions of Article 5.1(f), which relate to the inclusion or exclusion of months for calculation of the Annual Capacity Ratio, apply. Pursuant to Article 9.5, if the parties anticipate that any condition or event of Force Majeure will cause a capacity reduction, the parties may thereafter agree to reduce the Capacity Commitment, pursuant to Article 5.2(b), with the Supplier paying costs and damages to Duke for such reduction pursuant to Article 11.1.

ARTICLE 10 (Default) sets forth procedures to be followed in the event of default. Unless the default arises out of a condition or event of Force Majeure, in which event the provisions of Article 9 shall apply, the defaulting party is given 60 days to cure the default (except that if it cannot be cured within 60 days with the exercise of due diligence, the defaulting party may submit a plan for the other party's approval which will correct the default within a reasonable period of time not to exceed six months). If the defaulting party fails to submit such a plan, or if the other party declines to approve it, or if the defaulting party fails to cure the default in conformance with the plan, then the other party may exercise its rights and remedies as set forth in Article 10. Article 10.2 lists a variety of specific circumstances and events which constitute a default by Supplier.

ARTICLE 11 (Costs and Damages) sets forth certain damages which Supplier may be required to pay to Duke upon occurrence of: each capacity reduction (including agreed upon capacity reductions pursuant to Articles 5.2(b) or 9.5); termination by Duke due to Supplier's default; default by Supplier pursuant to Article 10 which does not result in a termination or reduction in capacity; or termination pursuant to Article 9.4. The costs and damages include: unpaid charges due to Duke including Interconnection Facilities charges; costs associated with the removal of Interconnection Facilities; loss due to early retirement of the Interconnection Facilities; and, in the event of a termination or capacity reduction, liquidated damages to compensate Duke for the detrimental effect on Duke's cost of power. The liquidated damages shall be calculated pursuant to the formulas in Appendix B. Also, in the event of a default by Supplier which does not result in a termination or capacity reduction, any actual damages incurred by Duke shall be paid by Supplier.

ARTICLE 12 (Operation of the Generating Facilities) sets forth certain responsibilities of the Supplier in its operation of the Facility. These include: Supplier is responsible for providing devices on its equipment to assure that there is no disturbance to Duke's facilities or other customers, and to protect Supplier's equipment from damage; Supplier agrees to operate and maintain the Facility "in accordance with applicable electric utility industry standards and good engineering practices" and in a prudent manner which will produce the maximum electric energy output consistent with the Agreement's dispatch and Capacity Commitment provisions; and Supplier shall coordinate its schedule for routine maintenance so that scheduled outages and capacity reductions occur during Off-Peak Hours or Off-Peak Months, with scheduled maintenance resulting in outages or capacity reductions restricted to 45 days per year. Article 12.3 includes a chart which sets forth the required minimum advance notice to Duke of scheduled outages according to the duration of the outage. Article 12.4 states that in the event of an emergency condition on Duke's system, Supplier shall increase or decrease the output of the Facility upon Duke's request, within the design limits of the facility.

ARTICLE 13 (Liability and Indemnity) sets forth liability and indemnity provisions for the Agreement. The indemnifying party agrees to be responsible for damages to persons or property arising out of the indemnifying party's negligent or tortious acts, errors or omissions, whether such persons or property are affiliated with the indemnifying party, the other party or third parties. Indirect and consequential damages are excluded.

ARTICLE 14 (Security) sets forth Supplier's obligation to provide security under the Purchased Power Agreement for its performance, including its obligation to pay costs and damages pursuant to Article 11.1. Such Security must be in place within 60 days after the Agreement is approved or

accepted by filing by the Commission, and shall be maintained through the term of the Agreement. Article 14.2 sets forth the formula which shall be used annually to determine the amount of security required, and provides that the Security may be reduced by 50 percent from the commencement of construction of the Facility until 15 days prior to the Commercial Operations Date. Article 14.3 specifies the form of security, which may be an irrevocable standby letter of credit, a performance bond or cash. Articles 14.4 and 14.5 contain provisions designed to ensure that the security remains in force continuously during the term of the Agreement.

ARTICLE 15 (Communications) sets forth procedures for communications and notices between the parties.

ARTICLE 16 (Assignability) requires the Supplier to advise Duke and the Commission of any plans to sell, transfer or assign the Facility, and restricts the rights of the parties to assign or subcontract the Agreement and its rights and duties. In most cases consent of the other party (which shall not be unreasonably withheld) is required prior to assignment or subcontracting. However, such consent is not required prior to an assignment by Duke to a parent, subsidiary or affiliated corporation, or by Supplier to a trustee or mortgagee pursuant to a financing agreement. In the case of any assignment, with or without prior consent, prior notice must be given to the other party, the assignee shall expressly assume the assignor's obligations (but no such assignment shall relieve the assignor of its obligations to perform in the event the assignee fails to perform), the assignment shall not impair any security given by Seller, and the contemplated assignee must obtain any necessary regulatory approvals including that of the Commission.

ARTICLE 17 (Miscellaneous) contains various contractual provisions. Supplier should review all of the provisions of Article 17.

APPENDICES:

APPENDIX A sets forth the rate or rate formulas.

APPENDIX B sets forth the formula for calculating liquidated damages.

APPENDIX C sets forth the estimated Interconnection Facilities charges.

APPENDIX D sets forth the formulas for calculating the power factor adjustment.

APPENDIX E includes Duke's Service Regulations in effect as of the date of execution of this Agreement.

APPENDIX D

SAMPLE REQUEST FOR PROPOSALS FOR LANDFILL GAS ENERGY PROJECT DEVELOPER

Department of Solid Waste

REQUEST FOR PROPOSALS - LANDFILL GAS

15 July 94

The City is soliciting proposals from environmental or energy management organizations, user industries, turnkey system providers and environmental engineering firms for the beneficial use of landfill gas (LFG).

BACKGROUND

The City owns and operates a 200+ acre Solid Waste Management Center (SWMC) which is managed by the Solid Waste Department. The SWMC contains a recently closed landfill having a footprint of approximately 52 acres. That landfill, the focus of this RFP, was originally placed on glacial till and is now capped with materials in compliance with New York's Part 360 regulations.

The cap design includes a membrane and a series of vent structures. Underneath the membrane is a permeable layer of natural materials which also contains a series of collection pipes, all linked to two header pipes emerging from under the cap at opposite points along the landfill's perimeter. A gravity leachate interception system has also been constructed beneath the perimeter of the landfill, leading to a single discharge point wherein any flowing condensate and residual LFG may be intercepted.

The design principle was to allow for conversion from a passive to an active LFG system by sealing the vents and activating a pumping system at one or both of the headers.

Initial measurements suggest natural production of approximately 975,000 cubic feet of LFG each day. This was based on a composite of low pressure measurements at 53 vent stacks. There are six other emission points were not measured at the time. Qualitative data is attached, as measured on a Landtec Gem 500. Data and observations suggest that the entire regime is currently sensitive to ambient air pressure differentials induced by wind.

Other features within the SWMC include:

- 1) a separate new active landfill with a present 10 acre footprint

and a loading rate of approximately 34,000 tons per year, which began operations in Sept. '92,

- 2) a 4,000 s.f. maintenance building for department vehicles and equipment,
- 3) overhead electric transmission lines with various voltages,
- 4) underground natural gas (high pressure) pipelines,
- 5) a 650,000 gallon glass lined steel open top storage tank for leachate (emergency use only), and
- 6) an improved roadway system between features.

Planned or contemplated improvements within or immediately adjacent to the SWMC include:

- a) a compost processing area for vegetative waste materials,
- b) artificial wetlands for partial or full treatment of landfill leachate,
- c) a major structure for processing recyclable materials, possibly linked with a privately operated manufacturing enterprise utilizing recycled materials as feedstock(s), and
- d) a new central garage facility within the SWMC for City owned vehicles.

Adjacent to the SWMC is an industrial park, including a major facility for the manufacture of air conditioning equipment and several other manufactures. Approximately 50 acres remain available for development. The Park is entirely within a NYS Economic Development Zone ("EDZ").

Nearby is a wastewater treatment plant which is owned and operated by the City (land linked). It contains a sludge incinerator and numerous pumps.

The City's Utilities Department operates two hydroelectric generation plants (combined 1.2 MW) and has plans for at least one additional plant in the near future.

Major intercepting sewer system components are located within contiguous City-owned rights of way.

RESPONDENTS SHOULD TAKE INTO CONSIDERATION THAT IT IS THE CITY'S INTENT TO MAXIMIZE THE USE AND BENEFIT OF ALL AVAILABLE CITY RESOURCES AND INFRASTRUCTURE IN THE MOST COST-EFFECTIVE MANNER POSSIBLE.

REQUEST FOR PROPOSALS

The City views the LFG at the SWMC as an untapped resource whose collection system is installed. Primary interest is in LFG utilization with maximum benefit to the City as a return on the substantial investment made in the SWMC to date. This benefit may take the form of one or more of the following:

- simplified sale of the LFG "as is, where is",
- royalties based on LFG utilization by others,
- direct earnings after additional investment in enterprise by the City, and
- realized savings from avoided costs (to obtain other conventional fuels).

The City and/or its agents are willing to consider conventional contracts, "Performance Based" contracts, partnerships, joint ventures, management agreements, and other appropriate mechanisms respondents may propose.

REQUIRED COMPONENTS OF RESPONSES

- 1) A basic component of all responsive proposals must be the provision of sufficient professional engineering services to accurately and responsibly portray technical issues regarding the complex medium of landfill gas, and do so gracefully within the arena of environmental regulations as they are administered by the New York State DEC and the federal EPA. As a minimum, flaring or any alternative backup methodology is to be included in order to avoid reversion to a passive venting system except under significant emergency conditions. A

permanent and adequate LFG monitoring system is to be included in this component.

- 2) Additional components should address one or more means by which the energy represented in combustible gas can be harnessed, either by direct combustion of LFG or subsequent to refinement. Proposals incorporating utilization of byproduct gas (from refinement) are encouraged.
- 3) Since LFG production is presumed to remain relatively constant throughout the year, additional components should also address levelizing consumption or incorporating storage if necessary or beneficial.
- 4) Any necessary design or structural adjustments to the existing LFG collection system must be clearly stated.
- 5) Proposals incorporating electrical energy distribution beyond a local regulated system should also address matters relating to wheeling.
- 6) Respondents are encouraged to incorporate design and operations procedures adjustments for the currently operating landfill (also within the SWMC) in order to capitalize on increasing amounts of LFG being generated therein.
- 7) Proposals should clearly state the nature of the initial working relationship between the City and the proposer. It should also state any proprietary interest the proposer has in other proposed or operating LFG utilization systems.
- 8) If proposers include subordinated or collaborative roles by other organizations, those roles should be clearly stated.

ILLUSTRATIONS OF POTENTIAL RELATIONSHIPS WITH AUBURN

- 1) As consultant, providing professional engineering or management services - with the City fully responsible for fiscal implementation with or without contracted operations services.
- 2) As turnkey provider of a designed, permitted and constructed facility with all user/sales agreements in place.

- 3) As wellhead purchaser of LFG with or without lease/purchase of real estate within the SWMC and/or industrial park.
- 4) As equity partner in the development and operation of a LFG system and/or related enterprise, utilizing subordinated engineering services.
- 5) As long term contractor for inclusion of LFG as part of more extensive solid waste management services.
- 6) As federal/state research and development agency, sharing an equity role.

Proposers are invited to counsel the City regarding the technical and business merits of as many LFG utilization options as appear to be practical for the City to independently or mutually pursue toward the goals of increasing revenue and/or avoiding costs; and, leveraging this resource as a development incentive for new enterprises. They may also be direct action proposals.

It is not the intent of this RFP to emphasize the need for further detailed quantitative or qualitative analysis of LFG presently generated within the SWMC.

Most aspects of proposals are considered to be public domain. Those aspects considered to be proprietary should be identified and bound separately, thereupon they will be honored as such. Until such time as formal negotiations begin with a selected proposer, it is suggested that cost and/or investment information be stated in ranges. Cost and/or investment information will be kept confidential during negotiations, but final agreements will be public domain.

PROPOSAL TIMETABLE

The City is actively pursuing construction projects which may benefit from the use of LFG. It is also mindful of the value lost while passive ventilation of LFG takes place. Due to the potential complexity of different proposals, only a target date of 1 Aug 94 has been established. Following an initial response of interest (together with any generic qualification information), the City will schedule a preproposal conference, during which time all available information regarding the SWMC, the neighboring industrial park, and potentially related City projects can be reviewed. Field orientation will also be provided. Potential proposers will be canvassed regarding preparation time before a final

proposal date is established.

TENTATIVE SCHEDULE

RFP available/mailed to prospective respondents	15 July 94
Initial expression of interest to City by	27 July 94
Preproposal conference, incl. site visit	wk of 1 Aug 94
Repeat preproposal conf., as needed	3rd wk of August
Proposal Submission Date:	15 Sept 94

CITY'S PROPOSAL EVALUATION TEAM

The team will consist of the City Manager, the Utilities Director, the Solid Waste Director, the Corporation Counsel, and a member of the City Council. The same team will later guide formal agreements to conclusion.

PROPOSAL EVALUATION CRITERIA

Proposals will be evaluated in terms of:

- | | |
|---|-----|
| • comprehensiveness | 20% |
| • creativity | 10% |
| • earnings potential for City | 50% |
| • recognition of solid waste priorities | 10% |
| • recognition of environmental concerns | 10% |

BRIEF SOLID WASTE HISTORY IN AUBURN

Since it's founding over 200 years ago, the City gradually became involved in waste disposal, first as provider of various dumps, then as collector. Burning dumps finally became a thing of the past in the 1950's with the most recent one being along the edge of North Division St. - at the entrance to the SWMC.

Collection services for garbage and trash became more precise as interest grew in recycling. At about the same time the State regulations were strengthening with regard to land disposal.

Disposal operations continued on the large site at the extreme Northwest corner of the City, but now as a sanitary landfill. Burning practices stopped. A new section of the site was utilized, but liner systems had not yet entered the regulatory regime. Wastes came in from many areas of Cayuga County, and even portions of neighboring Onondaga County.

Between the 1950's and 1980's many of Auburn's older structures were demolished as the economic base shifted away from a wide variety of manufacturing, which had origins along the waterway running through the center of the City. Remains of several factories and related structures ended up in the (common) landfill, which was extended laterally over the relatively tightly compacted natural ground. The entire site has a complex geologic history due in part to glacial movements.

As solid waste matters came more into focus, New York's plans and regulations evolved into some of the most sophisticated in the nation. It became a common objective to switch away from unlined landfills to lined ones.

Auburn's 50 acre+ landfill was one slated for closure. The City was destined by plan to continue providing and disposal capacity for the entire county. A replacement landfill was built on lands partly within the City and partly on lands acquired by the City and later annexed.

New York's regulatory standards for closure of all landfills continued to strengthen, and Auburn suddenly faced a multi million dollar closure investment toward the end of the landfill's permitted life. To meet those costs, the City worked out a Consent Order with the NYSDEC to continue operating in the then existing landfill, (known as Landfill No. 1), while constructing a new lined Landfill No. 2. During this window of opportunity for raising closure capital, the City allowed importation of large quantities of waste from distant sources, which was allowable since no lateral expansion of

the footprint was necessary.

Hence, during the final two years of its operation (ending 15 Sept 92), Landfill No. 1 commonly received up to 2,500 tons of waste per day, up from the routine amount by a factor of at least 10. All of those wastes were added to the relatively low and spread out landfill as it had evolved prior to importation. For that short period of time, the operation was more similar to those of larger metropolitan systems.

Landfill's No. 1's closure included some regarding, the placement of a more rational means to intercept remaining leachate, and a circumfrential roadway. Capping was begun on a North Slope even while filling continued to the South. The first detailed engineering work was done by C&S Engineers, and construction was by the Haseley Trucking Co.

After Landfill No. 2 opened, waste importation ceased. Tonnage abruptly returned to more "normal" levels. At that time, the South Slope closure work was begun with Stearns & Whaler providing engineering services and the Tug Hill Construction company doing the improvements. With winter shutdowns, it took just under two years to complete closure construction at an overall cost approaching \$10 million. Coordination of side by side engineering and construction was provided by the Department, with a welcomed role played by the Regional Office of the NYSDEC.

The City has developed an entrepreneurial approach to fiscal integrity. The SWMC will continue to play a strong role in providing revenue to the general fund. This will likely take several forms, as more and more management strategies are developed particular components of the solid waste stream. The City considers it prudent to only landfill those materials which cannot be managed within higher priority methodologies.

The benefit, as such, from large scale recent waste intake is now the natural production of an energy source. It is the City's objective to harness that energy to the benefit of the city as a whole, and/or the direct benefit to higher priority management of those wastes which do not have to be landfilled.

In its present configuration, the SWMC will continue to meet the needs of the Local Planning Unit (Cayuga County) for decades to come.

APPENDIX E

EPA MEMORANDUM ON POLLUTION CONTROL PROJECTS AND NEW SOURCE REVIEW (NSR) APPLICABILITY



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

JUL 1 1994

MEMORANDUM

SUBJECT: Pollution Control Projects and New Source Review (NSR) Applicability

FROM: John S. Seitz, Director
Office of Air Quality Planning and Standards (MD-10)

TO: Director, Air, Pesticides and Toxics
Management Division, Regions I and IV
Director, Air and Waste Management Division,
Region II
Director, Air, Radiation and Toxics Division,
Region III
Director, Air and Radiation Division,
Region V
Director, Air, Pesticides and Toxics Division,
Region VI
Director, Air and Toxics Division,
Regions VII, VIII, IX and X

This memorandum and attachment address issues involving the Environmental Protection Agency's (EPA's) NSR rules and guidance concerning the exclusion from major NSR of pollution control projects at existing sources. The attachment provides a full discussion of the issues and this policy, including illustrative examples.

For several years, EPA has had a policy of excluding certain pollution control projects from the NSR requirements of parts C and D of title I of the Clean Air Act (Act) on a case-by-case basis. In 1992, EPA adopted an explicit pollution control project exclusion for electric utility generating units [see 57 FR 32314 (the "WEPCO rule" or the "WEPCO rulemaking")]. At the time, EPA indicated that it would, in a subsequent rulemaking, consider adopting a formal pollution control project exclusion for other source categories [see 57 FR 32332]. In the interim, EPA stated that individual pollution control projects

involving source categories other than utilities could continue to be excluded from NSR by permitting authorities on a case-by-case basis [see 57 FR at 32320]. At this time, EPA expects to complete a rulemaking on a pollution control project exclusion for other source categories in early 1996. This memorandum and attachment provide interim guidance for permitting authorities on the approvability of these projects pending EPA's final action on a formal regulatory exclusion.

The attachment to this memorandum outlines in greater detail the type of projects that may qualify for a conditional exclusion from NSR as a pollution control project, the safeguards that are to be met, and the procedural steps that permitting authorities should follow in issuing an exclusion. Projects that do not meet these safeguards and procedural steps do not qualify for an exclusion from NSR under this policy. Pollution control projects potentially eligible for an exclusion (provided all applicable safeguards are met) include the installation of conventional or innovative emissions control equipment and projects undertaken to accommodate switching to an inherently less-polluting fuel, such as natural gas. Under this guidance, States may also exclude as pollution control projects some material and process changes (e.g., the switch to a less polluting coating, solvent, or refrigerant) and some other types of pollution prevention projects undertaken to reduce emissions of air pollutants subject to regulation under the Act.

The replacement of an existing emissions unit with a newer or different one (albeit more efficient and less polluting) or the reconstruction of an existing emissions unit does not qualify as a pollution control project. Furthermore, this guidance only applies to physical or operational changes whose primary function is the reduction of air pollutants subject to regulation under the Act at existing major sources. This policy does not apply to air pollution controls and emissions associated with a proposed new source. Similarly, the fabrication, manufacture or production of pollution control/prevention equipment and inherently less-polluting fuels or raw materials are not pollution control projects under this policy (e.g., a physical or operational change for the purpose of producing reformulated gasoline at a refinery is not a pollution control project).

It is EPA's experience that many bona fide pollution control projects are not subject to major NSR requirements for the simple reason that they result in a reduction in annual emissions at the source. In this way, these pollution control projects are outside major NSR coverage in accordance with the general rules for determining applicability of NSR to modifications at existing sources. However, some pollution control projects could result in significant potential or actual increases of some pollutants. These latter projects comprise the subcategory of pollution control projects that can benefit from this guidance.

A pollution control project must be, on balance, "environmentally beneficial" to be eligible for an exclusion. Further, an environmentally-beneficial pollution control project may be excluded from otherwise applicable major NSR requirements only under conditions that ensure that the project will not cause or contribute to a violation of a national ambient air quality standard (NAAQS), prevention of significant deterioration (PSD) increment, or adversely affect visibility or other air quality related value (AQRV). In order to assure that air quality concerns with these projects are adequately addressed, there are two substantive and two procedural safeguards which are to be followed by permitting authorities reviewing projects proposed for exclusion.

First, the permitting authority must determine that the proposed pollution control project, after consideration of the reduction in the targeted pollutant and any collateral effects, will be environmentally beneficial. Second, nothing in this guidance authorizes any pollution control project which would cause or contribute to a violation of a NAAQS, or PSD increment, or adversely impact an AQRV in a class I area. Consequently, in addition to this "environmentally-beneficial" standard, the permitting authority must ensure that adverse collateral environmental impacts from the project are identified, minimized, and, where appropriate, mitigated. For example, the source or the State must secure offsetting reductions in the case of a project which will result in a significant increase in a nonattainment pollutant. Where a significant collateral increase in actual emissions is expected to result from a pollution control project, the permitting authority must also assess whether the increase could adversely affect any national ambient air quality standard, PSD increment, or class I AQRV.

In addition to these substantive safeguards, EPA is specifying two procedural safeguards which are to be followed. First, since the exclusion under this interim guidance is only available on a case-by-case basis, sources seeking exclusion from major NSR requirements prior to the forthcoming EPA rulemaking on a pollution control project exclusion must, before beginning construction, obtain a determination by the permitting authority that a proposed project qualifies for an exclusion from major NSR requirements as a pollution control project. Second, in considering this request, the permitting authority must afford the public an opportunity to review and comment on the source's application for this exclusion. It is also important to note that any project excluded from major new source review as a pollution control project must still comply with all otherwise applicable requirements under the Act and the State implementation plan (SIP), including minor source permitting.

This guidance document does not supersede existing Federal or State regulations or approved SIP's. The policies set out in this memorandum and attachment are intended as guidance to be applied only prospectively (including those projects currently under evaluation for an exclusion) during the interim period until EPA takes action to revise its NSR rules, and do not represent final Agency action. This policy statement is not ripe for judicial review. Moreover, it is not intended, nor can it be relied upon, to create any rights enforceable by any party in litigation with the United States. Agency officials may decide to follow the guidance provided in this memorandum, or to act at variance with the guidance, based on an analysis of specific circumstances. The EPA also may change this guidance at any time without public notice. The EPA presently intends to address the matters discussed in this document in a forthcoming NSR rulemaking regarding proposed changes to the program resulting from the NSR Reform process and will take comment on these matters as part of that rulemaking.

As noted above, a detailed discussion of the types of projects potentially eligible for an exclusion from major NSR as a pollution control project, as well as the safeguards such projects must meet to qualify for the exclusion, is contained in the attachment to this memorandum. The Regional Offices should send this memorandum with the attachment to States within their jurisdiction. Questions concerning specific issues and cases should be directed to the appropriate EPA Regional Office. Regional Office staff may contact David Solomon, Chief, New Source Review Section, at (919) 541-5375, if they have any questions.

Attachment

cc: Air Branch Chief, Regions I-X
NSR Reform Subcommittee Members

Attachment

GUIDANCE ON EXCLUDING POLLUTION CONTROL PROJECTS FROM MAJOR NEW SOURCE REVIEW (NSR)

I. Purpose

The Environmental Protection Agency (EPA) presently expects to complete a rulemaking on an exclusion from major NSR for pollution control projects by early 1996. In the interim, certain types of projects (involving source categories other than utilities) may qualify on a case-by-case basis for an exclusion from major NSR as pollution control projects. Prior to EPA's final action on a regulatory exclusion, this attachment provides interim guidance for permitting authorities on the types of projects that may qualify on a case-by-case basis from major NSR as pollution control projects, including the substantive and procedural safeguards which apply.

II. Background

The NSR provisions of part C [prevention of significant deterioration (PSD)] and part D (nonattainment requirements) of title I of the Clean Air Act (Act) apply to both the construction of major new sources and the modification of existing major sources.¹ The modification provisions of the NSR programs in parts C and D are based on the broad definition of modification in section 111(a)(4) of the Act. That section contemplates a two-step test for determining whether activities at an existing major facility constitute a modification subject to new source requirements. In the first step, the reviewing authority determines whether a physical or operational change will occur. In the second step, the question is whether the physical or operational change will result in any increase in emissions of any regulated pollutant.

The definition of physical or operational change in section 111(a)(4) could, standing alone, encompass the most mundane activities at an industrial facility (even the repair or replacement of a single leaky pipe, or a insignificant change in the way that pipe is utilized). However, EPA has recognized that Congress did not intend to make every activity at a source subject to new source requirements under parts C and D. As a result, EPA has by regulation limited the reach of the modification provisions of parts C and D to only major modifications. Under NSR, a "major modification" is generally a physical change or change in the method of operation of a major stationary source which would result in a significant net emissions increase in the emissions of any regulated pollutant

¹The EPA's NSR regulations for nonattainment areas are set forth at 40 CFR 51.165, 52.24 and part 51, Appendix S. The PSD program is set forth in 40 CFR 52.21 and 51.166.

[see, e.g., 40 CFR 52.21(b)(2)(i)]. A "net emissions increase" is defined as the increase in "actual emissions" from the particular physical or operational change together with any other contemporaneous increases or decreases in actual emissions [see, e.g., 40 CFR 52.21(b)(3)(i)]. In order to trigger major new source review, the net emissions increase must exceed specified "significance" levels [see, e.g., 40 CFR 52.21(b)(2)(i) and 40 CFR 52.21(b)(23)]. The EPA has also adopted common-sense exclusions from the "physical or operational change" component of the definition of "major modification." For example, EPA's regulations contain exclusions for routine maintenance, repair, and replacement; for certain increases in the hours of operation or in the production rate; and for certain types of fuel switches [see, e.g., 40 CFR 52.21(b)(2)(iii)].

In the 1992 "WEPCO" rulemaking [57 FR 32314], EPA amended its PSD and nonattainment NSR regulations as they pertain to utilities by adding certain pollution control projects to the list of activities excluded from the definition of physical or operational changes. In taking that action, EPA stated it was largely formalizing an existing policy under which it had been excluding individual pollution control projects where it was found that the project "would be environmentally beneficial, taking into account ambient air quality" [57 FR at 32320; see also *id.*, n. 15].²

The EPA has provided exclusions for pollution control projects in the form of "no action assurances" prior to November 15, 1990 and nonapplicability determinations based on Act changes as of November 15, 1990 (1990 Amendments). Generally, these exclusions addressed clean coal technology projects and fuel switches at electric utilities.

Because the WEPCO rulemaking was directed at the utility industry which faced "massive industry-wide undertakings of pollution control projects" to comply with the acid rain provisions of the Act [57 FR 32314], EPA limited the types of projects eligible for the exclusion to add-on controls and fuel switches at utilities. Thus, pollution control projects under the WEPCO rule are defined as:

any activity or project undertaken at an existing electric utility steam generating unit for purposes of reducing emissions from such unit. Such activities or projects are limited to:

²This guidance pertains only to source categories other than electric utilities, and EPA does not intend for this guidance to affect the WEPCO rulemaking in any way.

(A) The installation of conventional or innovative pollution control technology, including but not limited to advanced flue gas desulfurization, sorbent injection for sulfur dioxide (SO₂) and nitrogen oxides (NO_x) controls and electrostatic precipitators;

(B) An activity or project to accommodate switching to a fuel which is less polluting than the fuel in use prior to the activity or project . . .

[40 CFR 51.165(a)(1)(xxv) (emphasis added)].
The definition also includes certain clean coal technology demonstration projects. Id.

The EPA built two safeguards into the exclusion in the rulemaking. First, a project that meets the definition of pollution control project will not qualify for the exclusion where the "reviewing authority determines that (the proposed project) renders the unit less environmentally beneficial . . ." [see, e.g., 51.165(a)(1)(v)(C)(8)]. In the WEPCO rule, EPA did not provide any specific definition of the environmentally-beneficial standard, although it did indicate that the pollution control project provision "provides for a case-by-case assessment of the pollution control project's net emissions and overall impact on the environment" [57 FR 32321]. This provision is buttressed by a second safeguard that directs permitting authorities to evaluate the air quality impacts of pollution control projects that could--through collateral emissions increases or changes in utilization patterns--adversely impact local air quality [see 57 FR 32322]. This provision generally authorizes, as appropriate, a permitting authority to require modelling of emissions increases associated with a pollution control project. Id. More fundamentally, it explicitly states that no pollution control project under any circumstances may cause or contribute to violation of a national ambient air quality standard (NAAQS), PSD increment, or air quality related value (AQRV) in a class I area. Id.³

³The WEPCO rule refers specifically to "visibility limitation" rather than "air quality related values." However, EPA clearly stated in the preamble to the final rule that permitting agencies have the authority to "solicit the views of others in taking any other appropriate remedial steps deemed necessary to protect class I areas. . . . The EPA emphasizes that all environmental impacts, including those on class I areas, can be considered. . . ." [57 FR 32322]. Further, the statutory protections in section 165(d) plainly are intended to protect against any "adverse impact on the AQRV of such [class I] lands

As noted, the WEPCO rulemaking was expressly limited to existing electric utility steam generating units [see, e.g., 40 CFR 51.165(a)(1)(v)(C)(8) and 51.165(a)(1)(xx)]. The EPA limited the rulemaking to utilities because of the impending acid rain requirements under title IV of the Act, EPA's extensive experience with new source applicability issues for electric utilities, the general similarity of equipment, and the public availability of utility operating projections. The EPA indicated it would consider adopting a formal NSR pollution control project exclusion for other source categories as part of a separate NSR rulemaking. The rulemaking in question is now expected to be finalized by early 1996. On the other hand, the WEPCO rulemaking also noted that EPA's existing policy was, and would continue to be, to allow permitting authorities to exclude pollution control projects in other source categories on a case-by-case basis.

III. Case-By-Case Pollution Control Project Determinations

The following sections describe the type of projects that may be considered by permitting authorities for exclusion from major NSR as pollution control projects and two safeguards that permitting authorities are to use in evaluating such projects--the environmentally-beneficial test and an air quality impact assessment. To a large extent, these requirements are drawn from the WEPCO rulemaking. However, because the WEPCO rule was designed for a single source category, electric utilities, it cannot and does not serve as a complete template for this guidance. Therefore, the following descriptions expand upon the WEPCO rule in the scope of qualifying projects and in the specific elements inherent in the safeguards. These changes reflect the far more complicated task of evaluating pollution control projects at a wide variety of sources facing a myriad of Federal, State, and local clean air requirements.

Since the safeguards are an integral component of the exclusion, States must have the authority to impose the safeguards in approving an exclusion from major NSR under this policy. Thus, State or local permitting authorities in order to use this policy should provide statements to EPA describing and affirming the basis for its authority to impose these safeguards absent major NSR. Sources that obtain exclusions from permitting authorities that have not provided this affirmation of authority are at risk in seeking to rely on the exclusion issued by the

(including visibility).\" Based on this statutory provision, EPA believes that the proper focus of any air quality assessment for a pollution control project should be on visibility and any other relevant AQRV's for any class I areas that may be affected by the proposed project. Permitting authorities should notify Federal Land Managers where appropriate concerning pollution control projects which may adversely affect AQRV's in class I areas.

permitting agency, because EPA may subsequently determine that the project does not qualify as a pollution control project under this policy.

A. Types of Projects Covered

1. Add-On Controls and Fuel Switches

In the WEPCO rulemaking, EPA found that both add-on emissions control projects and fuel switches to less-polluting fuels could be considered to be pollution control projects. For the purposes of today's guidance, EPA affirms that these types of projects are appropriate candidates for a case-by-case exclusion as well. These types of projects include:

- the installation of conventional and advanced flue gas desulfurization and sorbent injection for SO_2 ;
- electrostatic precipitators, baghouses, high efficiency multiclones, and scrubbers for particulate or other pollutants;
- flue gas recirculation, low- NO_x burners, selective non-catalytic reduction and selective catalytic reduction for NO_x ; and
- regenerative thermal oxidizers (RTO), catalytic oxidizers, condensers, thermal incinerators, flares and carbon adsorbers for volatile organic compounds (VOC) and toxic air pollutants.

Projects undertaken to accommodate switching to an inherently less-polluting fuel such as natural gas can also qualify for the exclusion. Any activity that is necessary to accommodate switching to a inherently less-polluting fuel is considered to be part of the pollution control project. In some instances, where the emissions unit's capability would otherwise be impaired as a result of the fuel switch, this may involve certain necessary changes to the pollution generating equipment (e.g., boiler) in order to maintain the normal operating capability of the unit at the time of the project.

2. Pollution Prevention Projects

It is EPA's policy to promote pollution prevention approaches and to remove regulatory barriers to sources seeking to develop and implement pollution prevention solutions to the extent allowed under the Act. For this reason, permitting authorities may also apply this exclusion to switches to inherently less-polluting raw materials and processes and certain

other types of "pollution prevention" projects.⁴ For instance, many VOC users will be making switches to water-based or powder-paint application systems as a strategy for meeting reasonably available control technology (RACT) or switching to a non-toxic VOC to comply with maximum achievable control technology (MACT) requirements.

Accordingly, under today's guidance, permitting authorities may consider excluding raw material substitutions, process changes and other pollution prevention strategies where the pollution control aspects of the project are clearly evident and will result in substantial emissions reductions per unit of output for one or more pollutants. In judging whether a pollution prevention project can be considered for exclusion as a pollution control project, permitting authorities may also consider as a relevant factor whether a project is being undertaken to bring a source into compliance with a MACT, RACT, or other Act requirement.

Although EPA is supportive of pollution control and prevention projects and strategies, special care must be taken in classifying a project as a pollution control project and in evaluating a project under a pollution control project exclusion. Virtually every modernization or upgrade project at an existing industrial facility which reduces inputs and lowers unit costs has the concurrent effect of lowering an emissions rate per unit of fuel, raw material or output. Nevertheless, it is clear that these major capital investments in industrial equipment are the very types of projects that Congress intended to address in the new source modification provisions [see Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901, 907-10 (7th Cir. 1990) (rejecting contention that utility life extension project was not a physical or operational change); Puerto Rican Cement Co., Inc. v. EPA, 889 F.2d 292, 296-98 (1st Cir. 1989) (NSR applies to modernization project that decreases emissions per unit of output, but increases economic efficiency such that utilization may increase and result in net increase in actual emissions)]. Likewise, the replacement of an existing emissions unit with a newer or different one (albeit more efficient and less polluting) or the

⁴For purposes of this guidance, pollution prevention means any activity that through process changes, product reformulation or redesign, or substitution of less polluting raw materials, eliminates or reduces the release of air pollutants and other pollutants to the environment (including fugitive emissions) prior to recycling, treatment, or disposal; it does not mean recycling (other than certain "in-process recycling" practices), energy recovery, treatment, or disposal [see Pollution Prevention Act of 1990 section 6602(b) and section 6603(5)(A) and (B); see also "EPA Definition of 'Pollution Prevention,'" memorandum from F. Henry Habicht II, May 28, 1992].

reconstruction of an existing emissions unit would not qualify as a pollution control project. Adopting a policy that automatically excludes from NSR any project that, while lowering operating costs or improving performance, coincidentally lowers a unit's emissions rate, would improperly exclude almost all modifications to existing emissions units, including those that are likely to increase utilization and therefore result in overall higher levels of emissions.

In order to limit this exclusion to the subset of pollution prevention projects that will in fact lower annual emissions at a source, permitting authorities should not exclude as pollution control projects any pollution prevention project that can be reasonably expected to result in an increase in the utilization of the affected emissions unit(s). For example, projects which significantly increase capacity, decrease production costs, or improve product marketability can be expected to affect utilization patterns. With these changes, the environment may or may not see a reduction in overall source emissions; it depends on the source's operations after the change, which cannot be predicted with any certainty.⁵ This is not to say that these types of projects are necessarily subject to major NSR requirements, only that they should not be excluded as pollution control projects under this guidance. The EPA may consider different approaches to excluding pollution prevention projects from major NSR requirements in the upcoming NSR rulemaking. Under this guidance, however, permitting authorities should carefully review proposed pollution prevention projects to evaluate whether utilization of the source will increase as a result of the project.

Furthermore, permitting authorities should have the authority to monitor utilization of an affected emissions unit or source for a reasonable period of time subsequent to the project to verify what effect, if any, the project has on utilization. In cases where the project has clearly caused an increase in utilization, the permitting authority may need to reevaluate the basis for the original exclusion to verify that an exclusion is still appropriate and to ensure that all applicable safeguards are being met.

⁵This is in marked contrast to the addition of pollution control equipment which typically does not, in EPA's experience, result in any increase in the source's utilization of the emission unit in question. In the few instances where this presumption is not true, the safeguards discussed in the next section should provide adequate environmental protections for these additions of pollution control equipment.

B. Safeguards

The following safeguards are necessary to assure that projects being considered for an exclusion qualify as environmentally beneficial pollution control projects and do not have air quality impacts which would preclude the exclusion. Consequently, a project that does not meet these safeguards does not qualify for an exclusion under this policy.

1. Environmentally-Beneficial Test

Projects that meet the definition of a pollution control project outlined above may nonetheless cause collateral emissions increases or have other adverse impacts. For instance, a large VOC incinerator, while substantially eliminating VOC emissions, may generate sizeable NO_x emissions well in excess of significance levels. To protect against these sorts of problems, EPA in the WEPCO rule provided for an assessment of the overall environmental impact of a project and the specific impact, if any, on air quality. The EPA believes that this safeguard is appropriate in this policy as well.

Unless information regarding a specific case indicates otherwise, the types of pollution control projects listed in III. A. 1. above can be presumed, by their nature, to be environmentally beneficial. This presumption arises from EPA's experience that historically these are the very types of pollution controls applied to new and modified emissions units. The presumption does not apply, however, where there is reason to believe that 1) the controls will not be designed, operated or maintained in a manner consistent with standard and reasonable practices; or 2) collateral emissions increases have not been adequately addressed as discussed below.

In making a determination as to whether a project is environmentally beneficial, the permitting authority must consider the types and quantity of air pollutants emitted before and after the project, as well as other relevant environmental factors. While because of the case-by-case nature of projects it is not possible to list all factors which should be considered in any particular case, several concerns can be noted.

First, pollution control projects which result in an increase in non-targeted pollutants should be reviewed to determine that the collateral increase has been minimized and will not result in environmental harm. Minimization here does not mean that the permitting agency should conduct a BACT-type review or necessarily prescribe add-on control equipment to treat the collateral increase. Rather, minimization means that, within the physical configuration and operational standards usually associated with such a control device or strategy, the

source has taken reasonable measures to keep any collateral increase to a minimum. For instance, the permitting authority could require that a low-NO_x burner project be subject to temperature and other appropriate combustion standards so that carbon monoxide (CO) emissions are kept to a minimum, but would not review the project for a CO catalyst or other add-on type options. In addition, a State's RACT or MACT rule may have explicitly considered measures for minimizing a collateral increase for a class or category of pollution control projects and requires a standard of best practices to minimize such collateral increases. In such cases, the need to minimize collateral increase from the covered class or category of pollution control projects can be presumed to have been adequately addressed in the rule.

In addition, a project which would result in an unacceptable increased risk due to the release of air toxics should not be considered environmentally beneficial. It is EPA's experience, however, that most projects undertaken to reduce emissions, especially add-on controls and fuel switches, result in concurrent reductions in air toxics. The EPA expects that many pollution control projects seeking an exclusion under this guidance will be for the purpose of complying with MACT requirements for reductions in air toxics. Consequently, unless there is reason to believe otherwise, permitting agencies may presume that such projects by their nature will result in reduced risks from air toxics.

2. Additional Air Quality Impacts Assessments

(a) General

Nothing in the Act or EPA's implementing regulations would allow a permitting authority to approve a pollution control project resulting in an emissions increase that would cause or contribute to a violation of a NAAQS or PSD increment, or adversely impact visibility or other AQRV in a class I area [see, e.g., Act sections 110(a)(2)(C), 165, 169A(b), 173]. Accordingly, this guidance is not intended to allow any project to violate any of these air quality standards.

As discussed above, it is possible that a pollution control project--either through an increase in an emissions rate of a collateral pollutant or through a change in utilization--will cause an increase in actual emissions, which in turn could cause or contribute to a violation of a NAAQS or increment or adversely impact AQRV's. For this reason, in the WEPCO rule the EPA required sources to address whenever 1) the proposed change would result in a significant net increase in actual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis; and 2) the permitting

authority has reason to believe that such an increase would cause or contribute to a violation of a NAAQS, increment or visibility limitation. If an air quality impact analysis indicates that the increase in emissions will cause or contribute to a violation of any ambient standard, PSD increment, or AQRV, the pollution control exclusion does not apply.

The EPA believes that this safeguard needs to be applied here as well. Thus, where a pollution control project will result in a significant increase in emissions and that increased level has not been previously analyzed for its air quality impact and raises the possibility of a NAAQS, increment, or AQRV violation, the permitting authority is to require the source to provide an air quality analysis sufficient to demonstrate the impact of the project. The EPA will not necessarily require that the increase be modeled, but the source must provide sufficient data to satisfy the permitting authority that the new levels of emissions will not cause a NAAQS or increment violation and will not adversely impact the AQRV's of nearby potentially affected class I areas.

In the case of nonattainment areas, the State or the source must provide offsetting emissions reductions for any significant increase in a nonattainment pollutant from the pollution control project. In other words, if a significant collateral increase of a nonattainment pollutant resulting from a pollution control project is not offset on at least a one-to-one ratio then the pollution control project would not qualify as environmentally beneficial.⁶ However, rather than having to apply offsets on a case-by-case basis, States may consider adopting (as part of their attainment plans) specific control measures or strategies for the purpose of generating offsets to mitigate the projected collateral emissions increases from a class or category of pollution control projects.

(b) Determination of Increase in Emissions

The question of whether a proposed project will result in an emissions increase over pre-modification levels of actual emissions is both complicated and contentious. It is a question that has been debated by the New Source Review Reform Subcommittee of the Clean Air Act Advisory Committee and is expected to be revisited by EPA in the same upcoming rulemaking that will consider adopting a pollution control project exclusion. In the interim, EPA is adopting a simplified approach

⁶Regardless of the severity of the classification of the nonattainment area, a one-to-one offset ratio will be considered sufficient under this policy to mitigate a collateral increase from a pollution control project. States may, however, require offset ratios that are greater than one-to-one.

to determining whether a pollution control project will result in increased emissions.

The approach in this policy is premised on the fact that EPA does not expect the vast majority of these pollution control projects to change established utilization patterns at the source. As discussed in the previous section, it is EPA's experience that add-on controls do not impact utilization, and pollution prevention projects that could increase utilization may not be excluded under this guidance. Therefore, in most cases it will be very easy to calculate the emissions after the change: the product of the new emissions rate times the existing utilization rate. In the case of a pollution control project that collaterally increases a non-targeted pollutant, the actual increase (calculated using the new emissions rate and current utilization pattern) would need to be analyzed to determine its air quality impact.

The permitting authority may presume that projects meeting the definition outlined in section III(A)(1) will not change utilization patterns. However, the permitting authority is to reject this presumption where there is reason to believe that the project will result in debottlenecking, loadshifting to take advantage of the control equipment, or other meaningful increase in the use of the unit above current levels. Where the project will increase utilization and emissions, the associated emissions increases are calculated based on the post-modification potential to emit of the unit considering the application of the proposed controls. In such cases the permitting agency should consider the projected increase in emissions as collateral to the project and determine whether, notwithstanding the emissions increases, the project is still environmentally beneficial and meets all applicable safeguards.

In certain limited circumstances, a permitting agency may take action to impose federally-enforceable limits on the magnitude of a projected collateral emissions increase to ensure that all safeguards are met. For example, where the data used to assess a projected collateral emissions increase is questionable and there is reason to believe that emissions in excess of the projected increase would violate an applicable air quality standard or significantly exceed the quantity of offsets provided, restrictions on the magnitude of the collateral increase may be necessary to ensure compliance with the applicable safeguards.

IV. Procedural Safeguards

Because EPA has not yet promulgated regulations governing a generally applicable pollution control project exclusion from major NSR (other than for electric utilities), permitting authorities must consider and approve requests for an exclusion

on a case-by-case basis, and the exclusion is not self-executing. Instead, sources must receive case-by-case approval from the permitting authority pursuant to a minor NSR permitting process, State nonapplicability determination or similar process.

[Nothing in this guidance voids or creates an exclusion from any applicable minor source preconstruction review requirement in any SIP that has been approved pursuant to section 110(a)(2)(C) and 40 CFR 51.160-164.] This process should also provide that the application for the exclusion and the permitting agency's proposed decision thereon be subject to public notice and the opportunity for public and EPA written comment. In those limited cases where the applicable SIP already exempts a class or category of pollution controls project from the minor source permitting public notice and comment requirements, and where no collateral increases are expected (e.g., the installation of a baghouse) and all otherwise applicable environmental safeguards are complied with, public notice and comment need not be provided for such projects. However, even in such circumstances, the permitting agency should provide advance notice to EPA when it applies this policy to provide an exclusion. For standard-wide applications to groups of sources (e.g., RACT or MACT), the notice may be provided to EPA at the time the permitting authority intends to issue a pollution control exclusion for the class or category of sources and thereafter notice need not be given to EPA on an individual basis for sources within the noticed group.

V. Emission Reduction Credits

In general, certain pollution control projects which have been approved for an exclusion from major NSR may result in emission reductions which can serve as NSR offsets or netting credits. All or part of the emission reductions equal to the difference between the pre-modification actual and post-modification potential emissions for the decreased pollutant may serve as credits provided that 1) the project will not result in a significant collateral increase in actual emissions of any criteria pollutant, 2) the project is still considered environmentally beneficial, and 3) all otherwise applicable criteria for the crediting of such reductions are met (e.g., quantifiable, surplus, permanent, and enforceable). Where an excluded pollution control project results in a significant collateral increase of a criteria pollutant, emissions reduction credits from the pollution control project for the controlled pollutant may still be granted provided, in addition to 2) and 3) above, the actual collateral increase is reduced below the applicable significance level, either through contemporaneous reductions at the source or external offsets. However, neither the exclusion from major NSR nor any credit (full or partial) for emission reductions should be granted by the permitting authority where the type or amount of the emissions increase which would result from the use of such credits would lessen the

environmental benefit associated with the pollution control project to the point where the project would not have initially qualified for an exclusion.

IV. Illustrative Examples

The following examples illustrate some of the guiding principles and safeguards discussed above in reviewing proposed pollution control projects for an exclusion from major NSR.

Example 1

PROJECT DESCRIPTION: A chemical manufacturing facility in an attainment area for all pollutants is proposing to install a RTO to reduce VOC emissions (including emissions of some hazardous pollutants) at the plant by about 3000 tons per year (tpy). The emissions reductions from the RTO are currently voluntary, but may be necessary in the future for title III MACT compliance. Although the RTO has been designed to minimize NO_x emissions, it will produce 200 tpy of new NO_x emissions due to the unique composition of the emissions stream. There is no information about the project to rebut a presumption that the project will not change utilization of the source. Aside from the NO_x increase there are no other environmental impacts known to be associated with the project.

EVALUATION: As a qualifying add-on control device, the project may be considered a pollution control project and may be considered for an exclusion. The permitting agency should:

- 1) verify that the NO_x increase has been minimized to the extent practicable, 2) confirm (through modeling or other appropriate means) that the actual significant increase in NO_x emissions does not violate the applicable NAAQS,⁷ PSD increment, or adversely impact any Class I area AQRV, and 3) apply all otherwise applicable SIP and minor source permitting requirements, including opportunity for public notice and comment.

Example 2

PROJECT DESCRIPTION: A source proposes to replace an existing coal-fired boiler with a gas-fired turbine as part of a cogeneration project. The new turbine is an exact replacement for the energy needs supplied by the existing boiler and will emit less of each pollutant on an hourly basis than the boiler did.

⁷If the source were located in an area in which nonattainment NSR applied to NO_x emissions increases, 200 tons of NO_x offset credits would be required for the project to be eligible for an exclusion.

EVALUATION: The replacement of an existing emissions unit with a new unit (albeit more efficient and less polluting) does not qualify for an exclusion as a pollution control project. The company can, however, use any otherwise applicable netting credits from the removal of the existing boiler to seek to net the new unit out of major NSR.

Example 3

PROJECT DESCRIPTION: A source plans to physically renovate and upgrade an existing process line by making certain changes to the existing process, including extensive modifications to emissions units. Following the changes, the source will expand production and manufacture and market a new product line. The project will cause an increase in the economic efficiency of the line. The renovated line will also be less polluting on a per-product basis than the original configuration.

EVALUATION: The change is not eligible for an exclusion as a pollution control project. On balance, the project does not have clearly evident pollution control aspects, and the resultant decrease in the per-product emissions rate (or factor) is incidental to the project. The project is a physical change or change in the method of operation that will increase efficiency and productivity.

Example 4

PROJECT DESCRIPTION: In response to the phaseout of chlorofluorocarbons (CFC) under title VI of the Act, a major source is proposing to substitute a less ozone-depleting substance (e.g., HCFC-141b) for one it currently uses that has a greater ozone depleting potential (e.g., CFC-11). A larger amount of the less-ozone depleting substance will have to be used. No other changes are proposed.

EVALUATION: The project may be considered a pollution control project and may be considered for an exclusion. The permitting agency should verify that 1) actual annual emissions of HCFC-141b after the proposed switch will cause less stratospheric ozone depletion than current annual emissions of CFC-11; 2) the proposed switch will not change utilization patterns or increase emissions of any other pollutant which would impact a NAAQS, PSD increment, or AQRV and will not cause any cross-media harm, including any unacceptable increased risk associated with toxic air pollutants; and 3) apply all otherwise applicable SIP and minor source permitting requirements, including opportunity for public notice and comment.

Example 5

PROJECT DESCRIPTION: An existing landfill proposes to install either flares or energy recovery equipment [i.e., turbines or internal combustion (IC) engines]. The reductions from the project are estimated at over 1000 tpy of VOC and are currently not necessary to meet Act requirements, but may be necessary some time in the future. In case A the project is the replacement of an existing flare or energy system and no increase in NO_x emissions will occur. In case B, the equipment is a first time installation and will result in a 100 tpy increase in NO_x. In case C, the equipment is an addition to existing equipment which will accommodate additional landfill gas (resulting from increased gas generation and/or capture consistent with the current permitted limits for growth at the landfill) and will result in a 50 tpy increase in NO_x.

EVALUATION: Projects A, B, and C may be considered pollution control projects and may be considered for an exclusion; however, in cases B and C, if the landfill is located in an area required to satisfy nonattainment NSR for NO_x emissions, the source would be required to obtain NO_x offsets at a ratio of at least 1:1 for the project to be considered for an exclusion. [NOTE: VOC-NO_x netting and trading for NSR purposes may be discussed in the upcoming NSR rulemaking, but it is beyond the scope of this guidance.] Although neither turbines or IC engines are listed in section III.A.1 as add-on control devices and would normally not be considered pollution control projects, in this specific application they serve the same function as a flare, namely to reduce VOC emissions at the landfill with the added incidental benefit of producing useful energy in the process.⁸

The permitting agency should: 1) verify that the NO_x increase has been minimized to the extent practicable; 2) confirm (through modeling or other appropriate means) that the actual significant increase in NO_x emissions will not violate the

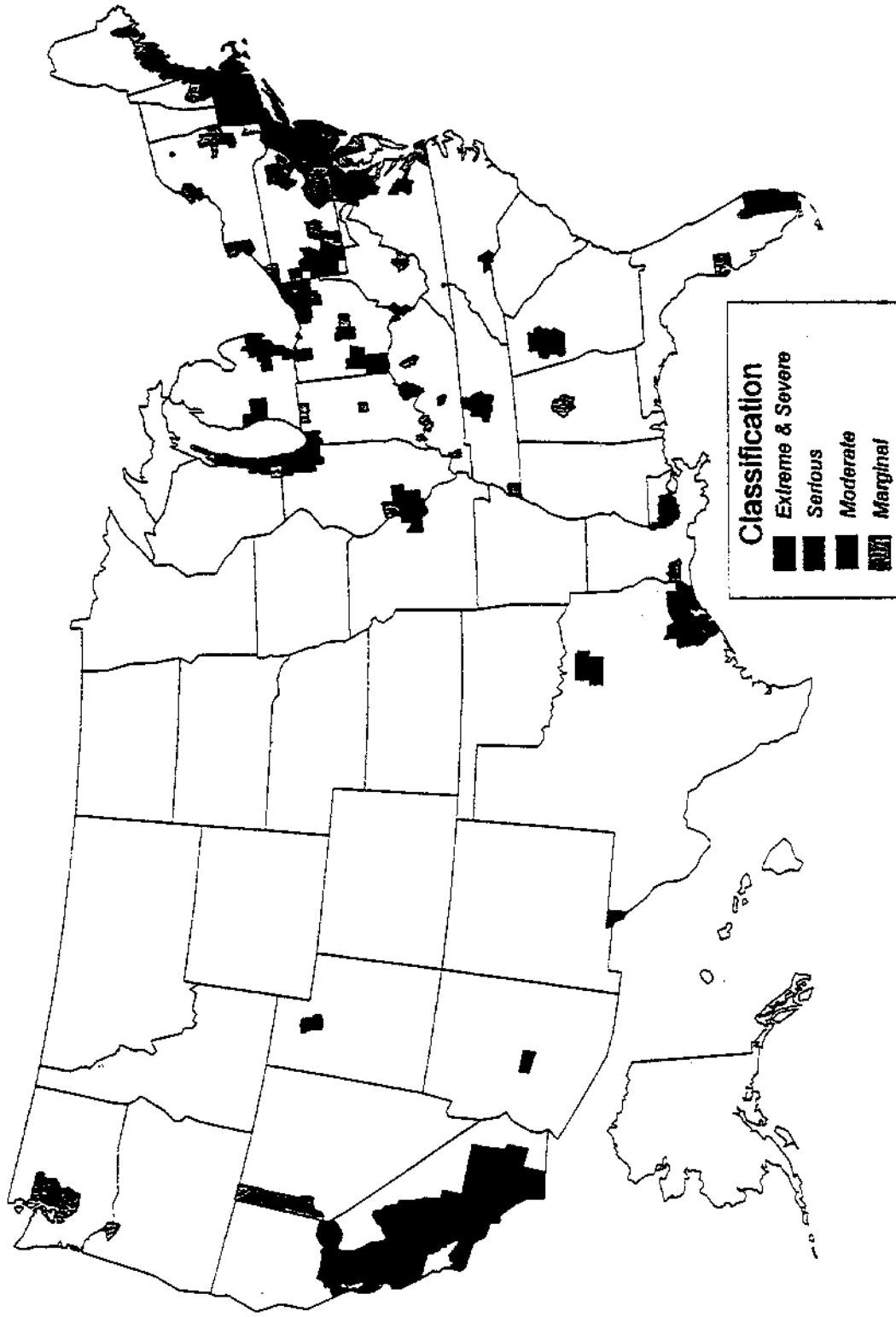
⁸The production of energy here is incidental to the project and is not a factor in qualifying the project for an exclusion as a pollution control project. In addition, any supplemental or co-firing of non-landfill gas fuels (e.g., natural gas, oil) would disqualify the project from being considered a pollution control project. The fuels would be used to maximize any economic benefit from the project and not for the purpose of pollution control at the landfill. However, the use of an alternative fuel solely as a backup fuel to be used only during brief and infrequent start-up or emergency situations would not necessarily disqualify an energy recovery project from being considered a pollution control project.

applicable NAAQS, PSD increment, or adversely impact any AQRV; and 3) apply all otherwise applicable SIP and minor source and, as noted above, in cases B and C ensures that NO_x offsets are provided in an area in which nonattainment review applies to NO_x emissions increases. permitting requirements, including opportunity for public notice and comment.

APPENDIX F

MAP AND LISTING OF NONATTAINMENT AREAS

Areas Designated Nonattainment for Ozone



Designated Nonattainment Areas as of September 1994

Note: Unclassified areas are not shown.

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update		1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
			A.Q. Value	Average Est. Exc.		
AL	Birmingham NA Area	Marginal	0.124	0.7	0.125	2.0
AZ	Phoenix	Moderate	0.147	4.0 (#4)	0.126	2.0
CA	Los Angeles South Coast Air Basin	Extreme	0.300	104.3	0.250	97.6
CA	Monterey Bay Unified NA Area	Moderate	0.108	0.4	0.104	0.0
CA	Sacramento Metro NA Area	Serious	0.150	9.7	0.150	3.6
CA	San Diego NA Area	Severe 15	0.150	11.8	0.159	4.0
CA	San Francisco-Bay NA Area	Moderate	0.120	0.7	0.130	2.0
CA	San Joaquin Valley NA Area	Serious	0.159	18.9	0.159	27.5
CA	Santa Barbara-Santa Maria-Lompoc	Moderate	0.123	1.0	0.114	0.0
CA	Southeast Desert Modified AQMD	Severe 17	0.200	59.3	0.180	72.6
CA	Ventura Co NA Area	Severe 15	0.150	15.9	0.144	9.0
CT	Greater Connecticut NA Area	Serious	0.158	7.5	0.153	6.0
DC-MD-VA	Washington NA Area	Serious	0.137	1.4	0.132	3.1
DE	Sussex Co NA Area	Marginal	0.118	1.0	0.115	0.0
FL	Miami-Port Lauderdale-W. Palm Beach	Moderate	0.106	0.0	0.122	1.0
FL	Tampa-St. Petersburg-Clearwater	Marginal	0.110	0.0	0.100	0.0
GA	Atlanta NA Area	Serious 17	0.149	4.2	0.162	4.3
IL-IN	Chicago-Gary-Lake County NA Area	Severe 17	0.145	4.7 (#5)	0.125	2.4
IL	Jersey Co NA Area	Marginal	0.112	0.7	0.127	2.0
IN	Evansville NA Area	Marginal	0.110	0.0	0.110	0.0
IN	Indianapolis NA Area	Marginal	0.104	0.0	0.104	0.0
IN	South Bend-Elkhart NA Area	Marginal	0.103	0.0	0.096	0.0
KY	Edmonson Co NA Area	Marginal	0.091	0.0	0.092	0.0
KY-WV	Huntington-Ashland NA Area	Moderate	0.122	1.0	0.122	1.0
KY	Lexington-Fayette NA Area	Marginal	0.100	0.0	0.103	0.0
KY-IN	Louisville NA Area	Moderate	0.130	2.2	0.140	2.0
KY	Owensboro NA Area	Marginal	0.104	0.0	0.106	0.0
KY	Paducah NA Area	Marginal	0.106	0.0	0.112	0.0
LA	Baton Rouge NA Area	Serious	0.135	1.8	0.127	3.0
LA	Lake Charles NA Area	Marginal	0.132	1.3 (#6)	0.108	0.0
MA-NH	Boston-Lawrence-Worcester NA Area	Serious	0.137	3.1	0.155	4.0
MA	Springfield (W. Mass) NA Area	Serious	0.141	4.6	0.133	6.2
MD	Baltimore NA Area	Severe 15	0.150	4.8	0.146	6.2
MD	Kent County and Queen Anne's County	Marginal	0.133	2.8	0.128	2.0
ME	Hancock Co and Waldo Co NA Area	Marginal	0.112	1.3 (#7)	0.094	0.0
ME	Knox Co and Lincoln Co NA Area	Moderate	0.134	2.3	0.122	1.2
ME	Lewiston - Auburn NA Area	Moderate	0.106	0.3	0.096	0.0
ME	Portland NA Area	Moderate	0.147	11.8	0.125	3.8
MI	Detroit-Ann Arbor NA Area	Moderate	0.122	1.0	0.122	1.0

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93, continued

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update		1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
			A.Q. Value	Average Est. Exc.		
MI	Grands Rapids NA Area	Moderate	0.146	3.4 (#8)	0.094	1.0
MI	Muskegon NA Area	Moderate	0.141	2.3	0.104	1.0
MO-KS	Kansas City NA Area	Attainment	0.114	0.3	0.114	1.0
MO-IL	St. Louis NA Area	Moderate	0.132	1.7	0.126	2.1
NC	Charlotte-Gastonia NA Area	Moderate	0.119	0.7	0.137	2.1
NC	Greensboro-Winston-Salem-High Point	Attainment	0.113	0.3	0.121	1.0
NC	Raleigh-Durham NA Area	Attainment	0.118	0.7	0.128	2.1
NH	Manchester NA Area	Marginal	0.087	0.0	0.086	0.0
NH	Portsmouth-Dover-Rochester, NH	Serious	0.143	2.2	0.107	1.1
NJ	Atlantic City NA Area	Moderate	0.122	1.0	0.115	0.0
NV	Reno	Marginal	0.089	0.0	0.089	0.0
NY	Albany-Schenectady-Troy NA Area	Marginal	0.104	0.0	0.106	0.0
NY	Buffalo-Niagara Falls NA Area	Marginal	0.106	0.0	0.090	0.0
NY	Essex Co NA Area	Marginal	0.116	0.0	0.100	0.0
NY	Jefferson Co NA Area	Marginal	0.110	0.0	0.092	0.0
NY-NJ-CT	New York-N. New Jersey-Long Island	Severe 17	0.158	6.1	0.165	6.0
NY	Poughkeepsie NA Area	Marginal	0.126	1.4	0.139	2.0
OH	Canton NA Area	Marginal	0.109	0.3	0.109	0.0
OH-KY	Cincinnati-Hamilton NA Area	Moderate	0.125	1.3	0.121	1.0
OH	Cleveland-Akron-Lorain NA Area	Moderate	0.125	1.7 (#9)	0.117	0.0
OH	Columbus NA Area	Marginal	0.118	0.3	0.105	0.0
OH	Dayton-Springfield NA Area	Moderate	0.112	0.0	0.120	1.0
OH	Toledo NA Area	Moderate	0.120	0.3	0.121	1.0
OH-PA	Youngstown-Warren-Sharon NA Area	Marginal	0.113	0.3	0.120	1.0
OR	Portland-Vancouver AQMA NA Area	Marginal	0.108	0.7	0.103	0.0
PA-NJ	Allentown-Bethlehem-Easton NA Area	Marginal	0.115	0.0	0.110	0.0
PA	Altoona NA Area	Marginal	0.105	0.0	0.100	0.0
PA	Erie NA Area	Marginal	0.110	0.0	0.107	0.0
PA	Harrisburg-Lebanon-Carlisle NA	Marginal	0.111	0.0	0.118	0.0
PA	Johnstown NA Area	Marginal	0.107	0.0	0.099	0.0
PA	Lancaster NA Area	Marginal	0.118	0.3	0.118	1.0
PA-NJ-DE-MD	Philadelphia-Wilmington-Trenton	Severe 15	0.156	10.3	0.147	5.2
PA	Pittsburgh-Beaver Valley NA Area	Moderate	0.119	0.7	0.124	0.0
PA	Reading NA Area	Moderate	0.118	0.3	0.110	0.0
PA	Scranton-Wilkes-Barre NA Area	Marginal	0.117	0.4	0.112	0.0
PA	York NA Area	Marginal	0.113	0.0	0.112	0.0

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93, continued

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update		1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
			A.Q. Value	Average Est., Exc.		
RI	Providence (all of RI) NA Area	Serious	0.152	4.0	0.117	1.4
SC	Cherokee Co NA Area	Attainment	0.105	0.3	0.108	0.0
TN	Knoxville NA Area	Attainment	0.118	0.0	0.120	0.0
TN	Memphis NA Area	Marginal	0.115	0.3	0.119	1.0
TN	Nashville NA Area	Moderate	0.124	1.1	0.126	2.1
TX	Beaumont-Port Arthur NA Area	Serious	0.130	2.7	0.122	0.0
TX	Dallas-Fort Worth NA Area	Moderate	0.141	2.0	0.140	2.3
TX	El Paso NA Area	Serious	0.136	3.7	0.135	4.1
TX	Houston-Galveston-Brazoria NA	Severe 17	0.200	6.3	0.197	10.4
UT	Salt Lake City-Ogden NA Area	Moderate	0.106	0.0	0.104	0.0
VA	Norfolk-Virginia Beach-Newport News	Marginal	0.131	1.7	0.131	3.0
VA	Richmond-Petersburg NA Area	Moderate	0.128	1.4	0.132	3.1
VA	Smyth County NA Area	Marginal	ND	ND (#10)	ND	ND
WA	Seattle - Tacoma NA Area	Marginal	0.105	0.0	0.100	0.0
WI	Door Co NA Area	Marginal	0.125	1.6	0.098	0.0
WI	Kewaunee Co NA Area	Moderate	0.107	0.8	0.095	0.0
WI	Manitowoc Co NA Area	Moderate	0.132	2.0	0.095	0.0
WI	Milwaukee-Racine NA Area	Severe 17	0.148	3.9	0.125	2.4
WI	Sheboygan NA Area	Moderate	0.139	2.6 (#11)	0.095	0.0
WI	Walworth Co NA Area	Marginal	0.120	0.3	0.093	0.0
WV	Charleston NA Area	Attainment	0.106	0.3	0.075	0.0
WV	Greenbrier NA Area	Marginal	0.101	0.4	0.090	0.0
WV	Parkersburg NA Area	Attainment	0.118	0.0	0.104	0.0

91 Nonattainment Areas

SOURCE:

EPA's air quality data system, the Aerometric Information Retrieval System (AIRS), with supplemental data from EPA Regional Offices.

NOTES:

1. Designations and classifications for ozone nonattainment areas as published in the Federal Register, 40 CFR Part 81. Unclassified and transitional nonattainment areas are not included in this listing.

2. The updated air quality value is estimated for the 1991-93 period using EPA guidance for calculating design values (Laxton Memorandum, June 18, 1990). Generally, the fourth highest monitored value with 3 complete years of data is

selected as the updated air quality value because the standard allows one exceedance for each year. It is important to note that the 1990 Clean Air Act Amendments required that O₃ nonattainment areas be classified on the basis of the design value at the time the Amendments were passed, generally the 1987-89 period was used.

3. The National Ambient Air Quality standard for ozone is 0.12 parts per million (ppm) daily maximum 1-hour average not to be exceeded more than once per year on average. The average estimated number of exceedances column shows the number of days the 0.12 ppm standard was exceeded on average at the site recording the highest updated air quality value. This is done after adjustment for incomplete, or missing days, during the 3-year period, 1991-93. The last two columns contain data from the site recording the highest second daily maximum 1-hour concentration in 1993. The last column shows the estimated exceedances for 1993 at the site recording the highest second maximum 1-hour concentration listed in the previous column.

4. Special purpose monitoring (SPM) operating during the ozone monitoring season.

5. The nonattainment/updated air quality value site for the Chicago NA Area is in Kenosha County, WI.

6. The Regional Office is reviewing the status of the area based on data through 1994.

7. Incomplete data reported in 1991.

8. Calculation of the updated air quality value and estimated exceedances adjusted to account for start-up of a LMOS study site with data only in 1991.

9. Data from a monitoring site located at the water treatment plant not used due to localized interference.

10. The site was located atop Whitetop Mountain, VA as part of the Mountain Cloud Study. Site elevation is 5520 feet. No data reported after 1988. This is a rural transport area. The nonattainment area is that portion of Whitetop Mountain above 4500 feet elevation.

11. Calculation of estimated exceedances adjusted for Wisconsin ozone season not yet reflected in AIRS.

Region I

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update		1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
			A.Q. Value	Average Est. Exc.		
CT	Greater Connecticut NA Area	Serious	0.158	7.5	0.153	6.0
MA-NH	Boston-Lawrence-Worcester NA Area	Serious	0.137	3.1	0.155	4.0
MA	Springfield (W. Mass) NA Area	Serious	0.141	4.6	0.133	6.2
ME	Hancock Co and Waldo Co NA Area	Marginal	0.112	1.3 (#7)	0.094	0.0
ME	Knox Co and Lincoln Co NA Area	Moderate	0.134	2.3	0.122	1.2
ME	Lewiston - Auburn NA Area	Moderate	0.106	0.3	0.096	0.0
ME	Portland NA Area	Moderate	0.147	11.8	0.125	3.8
NH	Manchester NA Area	Marginal	0.087	0.0	0.086	0.0
NH	Portsmouth-Dover-Rochester, NH	Serious	0.143	2.2	0.107	1.1
NY-NJ-CT	New York-N. New Jersey-Long Island	Severe 17	0.158	6.1	0.165	6.0
RI	Providence (all of RI) NA Area	Serious	0.152	4.0	0.117	1.4

Region II

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update		1993	
			A.Q. Value	Average Est. Exc.	2nd Daily Max 1-hr	Estimated Exceedances
NJ	Atlantic City NA Area	Moderate	0.122	1.0	0.115	0.0
NY	Albany-Schenectady-Troy NA Area	Marginal	0.104	0.0	0.106	0.0
NY	Buffalo-Niagara Falls NA Area	Marginal	0.106	0.0	0.090	0.0
NY	Essex Co NA Area	Marginal	0.116	0.0	0.100	0.0
NY	Jefferson Co NA Area	Marginal	0.110	0.0	0.092	0.0
NY-NJ-CT	New York-N. New Jersey-Long Island	Severe 17	0.158	6.1	0.165	6.0
NY	Poughkeepsie NA Area	Marginal	0.126	1.4	0.139	2.0
PA-NJ	Allentown-Bethlehem-Easton NA Area	Marginal	0.115	0.0	0.110	0.0
PA-NJ-DE-MD	Philadelphia-Wilmington-Trenton	Severe 15	0.156	10.3	0.147	5.2

Region III

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update		1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
			A.Q. Value	Average Est. Exo.		
DC-MD-VA	Washington NA Area	Serious	0.137	1.4	0.132	3.1
DE	Sussex Co NA Area	Marginal	0.118	1.0	0.115	0.0
MD	Baltimore NA Area	Severe 15	0.150	4.8	0.146	6.2
MD	Kent County and Queen Anne's County	Marginal	0.133	2.8	0.128	2.0
OH-PA	Youngstown-Warren-Sharon NA Area	Marginal	0.113	0.3	0.120	1.0
PA-NJ	Allentown-Bethlehem-Easton NA Area	Marginal	0.115	0.0	0.110	0.0
PA	Altoona NA Area	Marginal	0.105	0.0	0.100	0.0
PA	Erie NA Area	Marginal	0.110	0.0	0.107	0.0
PA	Harrisburg-Lebanon-Carlisle NA	Marginal	0.111	0.0	0.118	0.0
PA	Johnstown NA Area	Marginal	0.107	0.0	0.099	0.0
PA	Lancaster NA Area	Marginal	0.118	0.3	0.118	1.0
PA	Philadelphia-Wilmington-Trenton	Severe 15	0.156	10.3	0.147	5.2
PA-NJ-DE-MD	Pittsburgh-Beaver Valley NA Area	Moderate	0.119	0.7	0.124	0.0
PA	Reading NA Area	Moderate	0.118	0.3	0.110	0.0
PA	Scranton-Wilkes-Barre NA Area	Marginal	0.117	0.4	0.112	0.0
PA	York NA Area	Marginal	0.113	0.0	0.112	0.0
PA	Charleston NA Area	Moderate	0.106	0.3	0.075	0.0
WV	Greenbrier NA Area	Marginal	0.101	0.4	0.090	0.0
WV	Parkersburg NA Area	Moderate	0.118	0.0	0.104	0.0
WV	Norfolk-Virginia Beach-Newport News	Marginal	0.131	1.7	0.131	3.0
VA	Richmond-Petersburg NA Area	Moderate	0.128	1.4	0.132	3.1
VA	Smyth County NA Area	Marginal	ND	ND (#10)	ND	ND

Region IV

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update		1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
			A.Q. Value	Average Est. Exc.		
AL	Birmingham NA Area	Marginal	0.124	0.7	0.125	2.0
FL	Miami-Fort Lauderdale-W. Palm Beach	Moderate	0.106	0.0	0.122	1.0
FL	Tampa-St. Petersburg-Clearwater	Marginal	0.110	0.0	0.100	0.0
GA	Atlanta NA Area	Serious	0.149	4.2	0.162	4.3
KY	Edmonson Co NA Area	Marginal	0.091	0.0	0.092	0.0
KY-WV	Huntington-Ashland NA Area	Moderate	0.122	1.0	0.122	1.0
KY	Lexington-Fayette NA Area	Marginal	0.100	0.0	0.103	0.0
KY-IN	Louisville NA Area	Moderate	0.130	2.2	0.140	2.0
KY	Owensboro NA Area	Marginal	0.104	0.0	0.106	0.0
KY	Paducah NA Area	Marginal	0.106	0.0	0.112	0.0
NC	Charlotte-Gastonia NA Area	Moderate	0.119	0.7	0.137	2.1
NC	Greensboro-Winston-Salem-High Point	Attainment	0.113	0.3	0.121	1.0
NC	Raleigh-Durham NA Area	Attainment	0.118	0.7	0.128	2.1
OH-KY	Cincinnati-Hamilton NA Area	Moderate	0.125	1.3	0.121	1.0
SC	Cherokee Co NA Area	Attainment	0.105	0.3	0.108	0.0
TN	Knoxville NA Area	Attainment	0.118	0.0	0.120	0.0
TN	Memphis NA Area	Marginal	0.115	0.3	0.119	1.0
TN	Nashville NA Area	Moderate	0.124	1.1	0.126	2.1

December 1994

Region V

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update		1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
			A.Q. Value	Average Est. Exc.		
IL-IN	Chicago-Gary-Lake County NA Area	Severe 17	0.145	4.7 (#5)	0.125	2.4
IL	Jersey Co NA Area	Marginal	0.112	0.7	0.127	2.0
IN	Evansville NA Area	Marginal	0.110	0.0	0.110	0.0
IN	Indianapolis NA Area	Marginal	0.104	0.0	0.104	0.0
IN	South Bend-Elkhart NA Area	Marginal	0.103	0.0	0.096	0.0
MI	Detroit-Ann Arbor NA Area	Moderate	0.122	1.0	0.122	1.0
MI	Grande Rapids NA Area	Moderate	0.146	3.4 (#8)	0.094	1.0
MI	Muskegon NA Area	Moderate	0.141	2.3	0.104	1.0
OH	Canton NA Area	Marginal	0.109	0.3	0.109	0.0
OH-KY	Cincinnati-Hamilton NA Area	Moderate	0.125	1.3	0.121	1.0
OH	Cleveland-Akron-Lorain NA Area	Moderate	0.125	1.7 (#9)	0.117	0.0
OH	Columbus NA Area	Marginal	0.118	0.3	0.105	0.0
OH	Dayton-Springfield NA Area	Moderate	0.112	0.0	0.120	1.0
OH	Toledo NA Area	Moderate	0.120	0.3	0.121	1.0
OH-PA	Youngstown-Warren-Sharon NA Area	Marginal	0.113	0.3	0.120	1.0
WI	Door Co NA Area	Marginal	0.125	1.6	0.098	0.0
WI	Kewaunee Co NA Area	Moderate	0.107	0.8	0.095	0.0
WI	Manitowoc Co NA Area	Moderate	0.132	2.0	0.095	0.0
WI	Milwaukee-Racine NA Area	Severe 17	0.148	3.9	0.125	2.4
WI	Sheboygan NA Area	Moderate	0.139	2.6 (#11)	0.095	0.0
WI	Walworth Co NA Area	Marginal	0.120	0.3	0.093	0.0

Region VI

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update		1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
			A.Q. Value	Average Est. Exc.		
LA	Baton Rouge NA Area	Serious	0.135	1.8	0.127	3.0
LA	Lake Charles NA Area	Marginal	0.132	1.3 (#6)	0.108	0.0
TX	Beaumont-Port Arthur NA Area	Serious	0.130	2.7	0.122	0.0
TX	Dallas-Fort Worth NA Area	Moderate	0.141	2.0	0.140	2.3
TX	El Paso NA Area	Serious	0.136	3.7	0.135	4.1
TX	Houston-Galveston-Brasoria NA	Severe 17	0.200	6.3	0.197	10.4

Region VII

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update		1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
			A.Q. Value	Average Est. Exc.		
MO-KS MO-IL	Kansas City NA Area St. Louis NA Area	Attainment Moderate	0.114	0.3	0.114	1.0
			0.132	1.7	0.126	2.1

Region VIII

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	<u>1991-93 Update</u>		1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
			A.Q. Value	Average Est. Exo.		
UT	Salt Lake City-Ogden NA Area	Moderate	0.106	0.0	0.104	0.0

Region IX

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update		1993	
			A.Q. Value	Average Est. Exc.	2nd Daily Max 1-hr	Estimated Exceedances
AZ	Phoenix	Moderate	0.147	4.0 (#4)	0.126	2.0
CA	Los Angeles South Coast Air Basin	Extreme	0.300	104.3	0.250	97.6
CA	Monterey Bay Unified NA Area	Moderate	0.108	0.4	0.104	0.0
CA	Sacramento Metro NA Area	Serious	0.150	9.7	0.150	3.6
CA	San Diego NA Area	Severe 15	0.150	11.8	0.160	4.0
CA	San Francisco-Bay NA Area	Moderate	0.120	0.7	0.130	2.0
CA	San Joaquin Valley NA Area	Serious	0.160	18.9	0.160	27.5
CA	Santa Barbara-Santa Maria-Lompoc	Moderate	0.123	1.0	0.114	0.0
CA	Southeast Desert Modified AQMD	Severe 17	0.200	59.3	0.180	72.6
CA	Ventura Co NA Area	Severe 15	0.150	15.9	0.144	9.0
NV	Reno	Marginal	0.089	0.0	0.089	0.0

Region X

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	<u>1991-93 Update</u>		1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
			A.Q. Value	Average Est. Exc.		
OR WA	Portland-Vancouver AQMA NA Area Seattle - Tacoma NA Area	Marginal Marginal	0.108	0.7	0.103	0.0
			0.105	0.0	0.100	0.0

SOURCE: EPA's air quality data system, the Aerometric Information Retrieval System (AIRS), with supplemental data from EPA Regional Offices.

NOTES:

1. Designations and classifications for ozone nonattainment areas as published in the Federal Register, 40 CFR Part 81. *Unclassified and transitional nonattainment areas are not included in this listing.*
2. The updated air quality value is estimated for the 1991-93 period using EPA guidance for calculating design values (Laxton Memorandum, June 18, 1990). Generally, the fourth highest monitored value with 3 complete years of data is selected as the updated air quality value because the standard allows one exceedance for each year. It is important to note that the 1990 Clean Air Act Amendments required that O₃ nonattainment areas be classified on the basis of the design value at the time the Amendments were passed, generally the 1987-89 period was used.
3. The National Ambient Air Quality standard for ozone is 0.12 parts per million (ppm) daily maximum 1-hour average not to be exceeded more than once per year on average. The average estimated number of exceedances column shows the number of days the 0.12 ppm standard was exceeded on average at the site recording the highest updated air quality value. This is done after adjustment for incomplete, or missing days, during the 3-year period, 1991-93. The last two columns contain data from the site recording the highest second daily maximum 1-hour concentration in 1993. The last column shows the estimated exceedances for 1993 at the site recording the highest second maximum 1-hour concentration listed in the previous column.
4. Special purpose monitoring (SPM) operating during the ozone monitoring season.
5. The nonattainment/updated air quality value site for the Chicago NA Area is in Kenosha County, WI.
6. The Regional Office is reviewing the status of the area based on data through 1994.
7. Incomplete data reported in 1991.
8. Calculation of the updated air quality value and estimated exceedances adjusted to account for start-up of a LMOS Study site with data only in 1991.
9. Data from a monitoring site located at the water treatment plant not used due to localized interference.
10. The site was located atop Whitetop Mountain, VA as part of the Mountain Cloud Study. Site elevation is 5520 feet. No data reported after 1988. This is a rural transport area. The nonattainment area is that portion of Whitetop Mountain above 4500 feet elevation.
11. Calculation of estimated exceedances adjusted for Wisconsin ozone season not yet reflected in AIRS.

APPENDIX G

LISTING OF MUNICIPAL SOLID WASTE LANDFILL ORGANIZATIONS AND RELATED SERVICE PROVIDERS

**Listing of Municipal Solid Waste Landfill Organizations
and Related Service Providers**

Solid Waste Association of North America
(SWANA)
P.O. Box 7219
Silver Spring, MD 20910-7219
Contact: Michael Ohlsen
Phone: (301) 585-2989
Fax: (301) 585-7068

Environmental Industry Associations (EIA)/
National Solid Wastes Management
Association (NSWMA)
4301 Connecticut Avenue, NW
Suite 300
Washington, DC 20008
Contact: Ed Repa
Phone: (202) 244-4700
Fax: (202) 966-4818

Association of State and Territorial Solid
Waste Management Officials (ASTSWMO)
Hall of States
Suite 343
444 North Capitol Street, NW
Washington, DC 20001
Phone: (202) 624-5828
Fax: (202) 624-7875

National Business Industries Association
122 C Street, NW
Fourth Floor
Washington, DC 20001
Phone: (202) 383-2540
Fax: (202) 383-2670

Department of Energy Regional Biomass
Energy Program
Office of National Programs
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585
Contact: N. Michael Voorhies,
National Coordinator
Phone: (202) 586-9104

American Public Works Association
1301 Pennsylvania Avenue, NW
Suite 501
Washington, DC 20004
Contact: Sarah Layton
Phone: (202) 347-0612
Fax: (202) 737-9153

Regional Biomass Energy Programs:

Northeast Region
Richard Handley, Program Manager
CONEG Policy Research Center,
Inc.
400 North Capitol Street, NW
Suite 382
Washington, DC 20001
Phone: (202) 624-8454
Fax: (202) 624-8463

Northwest Region
Jeff James, Program Manager
U.S. Department of Energy
Seattle Regional Support Office
905 NE 11th Avenue
Portland, OR 97232
Phone: (503) 230-3449
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APPENDIX H
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APPENDIX I

ACID RAIN FACT SHEET



United States
Environmental Protection
Agency

Air and
Radiation
(6204-J)

EPA 430-K-94-014
November 1994

Landfill Methane and Clean Air Act Opportunities

Incentives from the Acid Rain Program



*Photo courtesy of New England Electric
System*

The environmental benefits of generating electricity from landfill methane now have an added, quantifiable value. Through an innovative system of tradeable emission allowances, Title IV of the Clean Air Act has increased the value of electricity generated from landfill methane.



Methane gas emissions from our country's growing landfill sites are a serious threat to greenhouse gas stabilization. Capturing methane from landfill sites for electrical generation serves both economic and environmental goals. Landfill methane is already a cost-effective energy resource in many areas of the country. The Clean Air Act incentives will further enhance the cost-effectiveness of landfill methane energy projects.

The Clean Air Act Incentives

The 1990 Clean Air Act Amendments call for a 10 million ton annual reduction in national SO₂ emissions from 1980 levels. This program creates a new tradeable commodity, the SO₂ emission allowance. Each allowance represents an authorization to emit one ton of SO₂ (i.e., a unit that emits 5,000 tons of SO₂ must hold at least 5,000 allowances that are usable that year). By avoiding the emission of SO₂ with landfill methane systems, utilities will both earn and save tradeable emission allowances. And these emission allowances have a real market value.

To promote pollution prevention, Title IV of the Clean Air Act includes two incentives for energy efficiency and renewable energy. These incentives are:

1. Avoided emissions
2. Conservation and Renewable Energy Reserve

Avoided emissions is perhaps the most lucrative of the incentives; each ton of SO₂ avoided through the generation of electricity from landfill methane saves one emission allowance. Allowances are saved at the utility's own rate of

emissions. The avoided emissions incentive is automatic; there are no application or verification requirements.



The Sonoma County, California landfill gas-to-energy facility. Photo courtesy of Landfill Energy Systems.

The Conservation and Renewable Energy Reserve is a special bonus pool of 300,000 allowances set aside to reward new initiatives in technologies such as landfill methane. For every 500 MWh of electricity generated through landfill methane systems, a utility earns one allowance from the Reserve.

For more information on these incentives, see *Energy Efficiency and Renewable Energy: Opportunities from Title IV of the Clean Air Act*.¹

1. US EPA, *Energy Efficiency and Renewable Energy: Opportunities from Title IV of the Clean Air Act*, Document no. EPA 430-R-94-001, February 1994. To obtain a copy, contact the Acid Rain Hotline at (202) 233-9620.

Valuing the Incentives

In general, the value of the Clean Air Act incentives will be the number of allowances earned or saved by the landfill methane installation multiplied by the market price of an SO₂ emission allowance. The hypothetical example below illustrates the potential savings from the Clean Air Act incentives.²

The market for tradeable emission allowances is continuing to evolve. A recent report issued by the Electric Power Research Institute (EPRI) indicates that prices could rise from \$250 per allowance in 1995 to \$480 per allowance in 2007.³ Price signals are also being provided by private trades and trading exchanges.

Example

In 1994, a utility installs 7 MW of capacity from landfill methane sites. The utility will enter the Acid Rain Program in the year 2000, and thus is eligible to earn Reserve allowances until 2000. Assuming a typical capacity factor of 0.85, the value of the Reserve allowances is calculated as follows:

$$\begin{aligned} 7 \text{ MW} \times 8,760 \text{ hours/yr} \times 0.85 &= 52,122 \text{ MWh/yr} \\ 52,122 \text{ MWh/yr} \div 500 \text{ MWh/allowance} &= 104 \text{ allow./yr} \\ \$250/\text{allowance} \times 104 \text{ allowances/yr} &= \$26,000/\text{yr} \end{aligned}$$

Thus, for the six years from 1994 through 1999, the utility could earn \$156,000 from the Reserve alone. However, landfill methane will continue to add value in the year 2000 and beyond through the avoided emissions incentive. And the benefits from avoided emissions will be even greater than those from the Reserve.

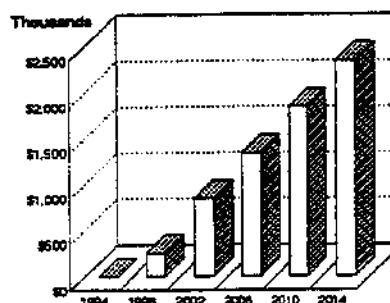
Assuming the utility's marginal rate of SO₂ emissions is 1.2 lbs/mmBtu (the emission limit for the Acid Rain Program) and a typical heat rate of 10,000 Btu/kWh, the value of avoided emissions in the year 2000 is:

$$\begin{aligned} 1.2 \text{ lbs/mmBtu} \times 10,000 \text{ Btu/kWh} \times \text{mmBtu}/1,000,000 \text{ Btu} &= 0.012 \text{ lbs/kWh} \\ 52,122,000 \text{ kWh} \times 0.012 \text{ lbs/kWh} \times 1 \text{ ton}/2000 \text{ lbs} &= 313 \text{ tons} = 313 \text{ allowances} \\ 313 \text{ allowances} \times \$340/\text{allowance} &= \$106,420 \end{aligned}$$

Assuming a 20 year project life and a 6% discount factor, the net present value of the Clean Air Act incentives for this landfill methane project is \$980,000.

Since landfill methane is a local resource, transmission losses are reduced and thus further improve the project's cost-effectiveness.

Cumulative Value of the SO₂ Incentives



2. For a more detailed explanation of the calculations in this example, contact the Acid Rain Hotline at (202) 233-9620 and ask for the *Landfill Methane Example*.

3. EPRI, *Integrated Analysis of Fuel, Technology and Emission Allowance Markets: Electric Utility Responses to the Clean Air Act Amendments of 1990*, Report no. TR-102510, August 1993, p. 1-20.

	1995	2000	2003	2007
Price (\$/ton)	\$250	\$340	\$400	\$480

Utility Allies: Tapping the Potential of Landfill Methane

By purchasing electricity generated from landfill gas, utilities gain a clean, renewable energy source, produce valuable reductions in local air pollutants and greenhouse gases, and build a more diverse and local resource base. To mobilize the use of landfill gas as an energy resource, EPA has created the Landfill Methane Outreach Program.

To become a Utility Ally in this program, a utility agrees to take advantage of the best opportunities for obtaining power from landfill gas. In turn, EPA recognizes and publicizes the utility's efforts and can assist in the evaluation and development of projects. The result is a win for the utility and its customers, and a win for the environment and the economy.

EPA estimates that over 700 landfills across the US could install economically viable landfill gas energy recovery systems, yet only about 115 facilities are in place. The EPA Landfill Methane Outreach Program is working to overcome the informational, regulatory, and other barriers that prevent these otherwise economical projects from going forward.

For more information on how your utility can become a Utility Ally, please contact EPA's Landfill Methane Program at (202) 233-9042.



Complying Cost-Effectively

Landfill methane resources can be cost-effective components to an integrated compliance strategy by:

- ◆ Complementing or offsetting the use of other compliance strategies such as fuel-switching;
- ◆ Delaying or eliminating the need for expensive alternative strategies such as scrubbing;
- ◆ Helping to avoid the noncompliance penalty of \$2,000 per ton of SO₂; and

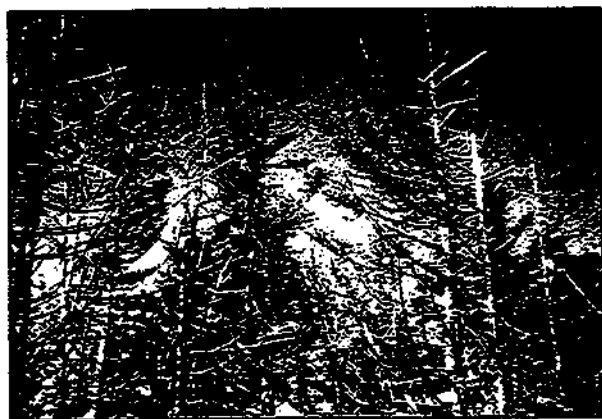
- ◆ Increasing revenues through the sale of extra allowances.

The extent to which the Clean Air Act incentives affect the financial outlook of landfill methane systems will depend upon each utility's own circumstances. Utilities that currently emit high levels of SO₂ can benefit significantly from the incentives. However, even utilities already in compliance can benefit from the revenues generated from extra allowances.

Benefiting the Environment

Emissions from fossil fuel generation harm waters and forests, endanger animal species, accelerate the decay of buildings and monuments, and impair public health. In many sensitive lakes and streams acidification has completely eradicated fish species.

Research has pointed to the increased health risks from particulate matter, which includes sulfates and other pollutants emitted during the combustion of fossil fuels. A recent study by Harvard University's School of Public Health linked these emissions to higher mortality rates and lung dysfunction in children and other sensitive populations.⁴



Emissions from fossil-fuel sources have damaged many forests.

Electricity generated from landfill methane helps combat not only acid rain, but other environmental harms as well, including global climate change. Landfill methane systems avoid emissions of SO₂, toxics, and particulates, as well as the production of ash and scrubber sludge.

Electricity generated from landfill methane will also help minimize emissions affecting

global climate change. Not only does this resource offset emissions from fossil fuel energy generation, but it also prevents the escape of methane gas, a greenhouse gas that is over 20 times more potent than carbon dioxide. Every 10,000 kilowatt hours of electricity generated from landfill methane is equivalent to:⁵



Planting 23,680 Trees per Year, or



Eliminating 360 Barrels of Crude Oil

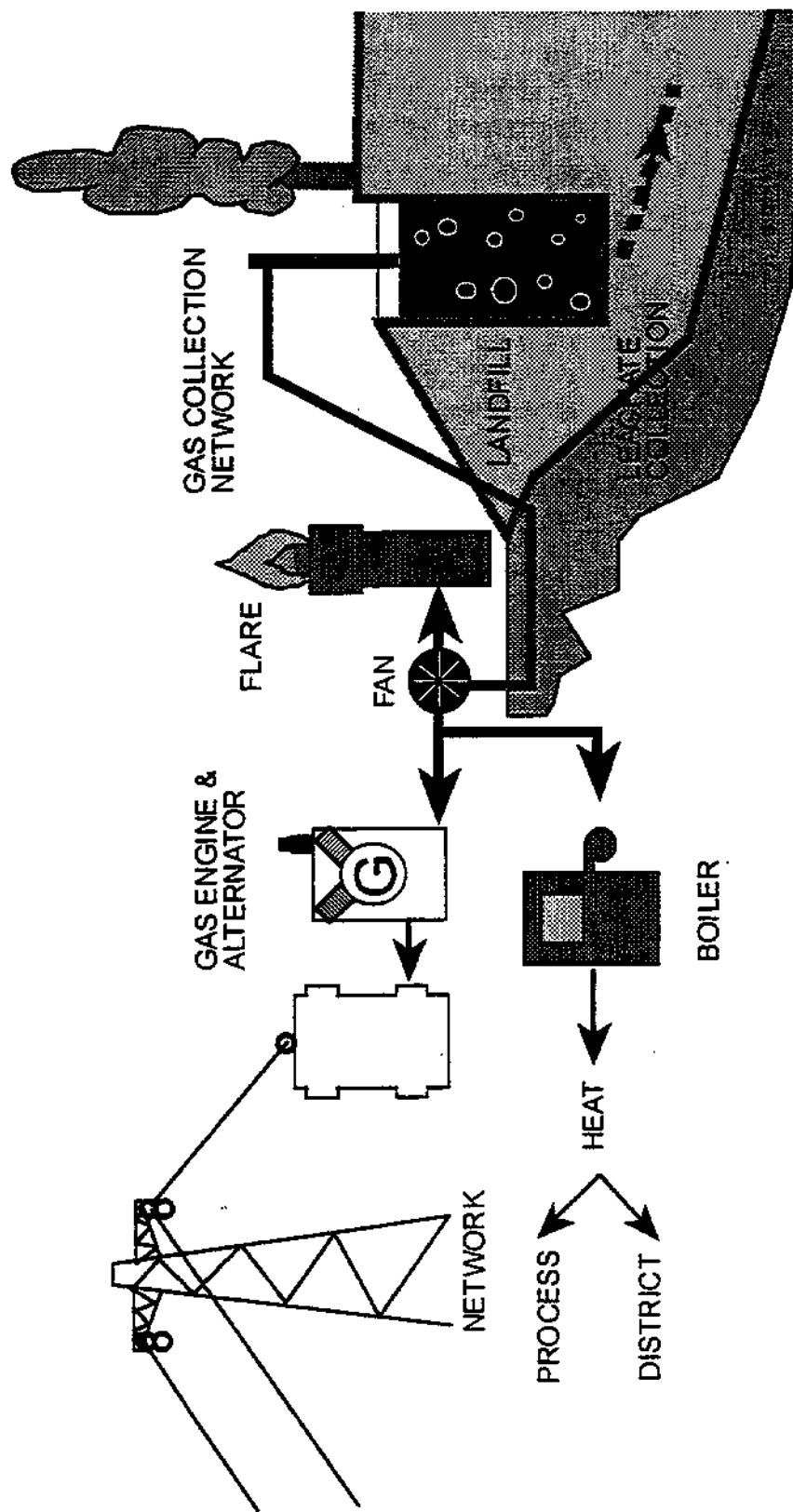
Landfill methane systems can be cost-effective solutions for simultaneously eliminating multiple pollutants. Rather than installing costly controls for each pollutant, landfill methane technology can be a solution for many pollutants. Landfill methane systems also provide insurance against the risk of future environmental regulations, including regulations on greenhouse gas emissions.

The real, quantifiable value of the Clean Air Act incentives can maximize a utility's overall cost-effectiveness in serving its customers and protecting the environment.

4. Dockery, Douglas W., et al., *An Association between Air Pollution and Mortality in Six US Cities*, The New England Journal of Medicine, vol. 329, no. 24, December 9, 1993, p. 1753-9.

5. Based on the 1990 average CO₂ emission rate for US utility generation.

Landfill Methane Recovery Process



Landfill gas is generated naturally through the bacterial decomposition of organic matter deposited in a sanitary landfill. Gas collection systems pull the gas from a series of wells to a central processing facility. Landfill gas is typically a medium Btu gas that has a number of energy applications. The most prevalent use is production of electricity for sale to the local utility. The gas may also be employed directly for use as boiler fuel and industrial process heat or converted for use as compressed natural gas for vehicle fuel.

Utility Profile: Detroit Edison Company

As the landfill gas recovery industry evolved in the 1980s, Detroit Edison became active in developing Michigan's first landfill gas-fired combustion turbine generating station. The 6.6-megawatt facility has safely and reliably operated at more than 85 percent capacity since achieving commercial operation in 1988.

Sited on a landfill owned by the City of Riverview, 20 miles south of Detroit, the small power production facility uses enough methane gas to generate electricity for about 6,000 homes. More than 100 gas wells on the 150-acre site collect about 4.3-million cubic feet of landfill gas daily to generate the power, which is sold to Detroit Edison.

While the project's 225,000 megawatt-hours of electricity is a small portion of Detroit Edison's overall power production, the environmental significance is impressive. By capturing more than 8 million cubic feet of landfill gas, this project has prevented more than 1,200 tons of sulfur dioxide emissions which would have been produced by fossil-fueled power generation. Each day the project directly destroys more than 2 million cubic feet of methane, a potent greenhouse gas.



Riverview, Michigan landfill gas-to-energy facility

Detroit Edison's involvement with 120-acre Sonoma Central landfill in California is relatively new. Through a subsidiary, landfill gas is collected, cleaned, compressed and delivered as fuel to a plant producing 3.2 megawatts. Sonoma County, owner of the facility, has been selling the electricity since May 1993. The facility uses about 1,200 cubic feet per minute of landfill gas to produce its power.

The Riverview and Sonoma facilities are licensed to operate well into the 21st century. Their success has prompted Detroit Edison to pursue similar ventures in Florida, Illinois, Texas, Ohio, and elsewhere in Michigan.

For More Information

Write to:

**US Environmental Protection Agency
Acid Rain Division (6204J)
Energy Efficiency and Renewable Energy
Section
401 M Street, SW
Washington, DC 20460**

If you have further questions or would like to receive any other publications, please call the Acid Rain Hotline at (202) 233-9620. An Energy Efficiency and Renewable Energy staff member will return your call within 24 hours.

APPENDIX J
GLOSSARY OF TERMS

Glossary of Terms

AFFECTED LANDFILL: Landfills that meet criteria set by the EPA under authority of Title I of the Clean Air Act for capacity, age, and emission rates; affected landfills are required to collect and combust their landfill gas

ATTAINMENT AREA: A geographic region that meets National Ambient Air Quality Standards (NAAQS) for specific air pollutants

AVOIDED COST: The cost a utility would incur to generate the next increment of electric capacity using its own resources; many landfill gas projects' buyback rates are based on avoided costs

BASELOAD: A term referring to the energy use of a facility that has a consistent, year-round need for energy; baseload can also refer to the minimum amount of electricity supplied to a facility on a continuous basis

BEST AVAILABLE CONTROL TECHNOLOGY (BACT): The most stringent technology available for controlling emissions; major sources are required to use BACT, unless it can be demonstrated that it is not feasible due to energy, environmental, or economic reasons

BUYBACK RATE: The price a utility will pay a third party supplier for electricity or gas

CAPACITY FACTOR: The ratio of the energy produced by a piece of equipment during a given time period to the energy the unit could have produced if it had been operating at its full rated capacity

CAPACITY PRICE: The fixed price in \$/kW a utility pays a third party supplier for a guaranteed availability of generating capacity; capacity price is based on the capital costs of a generating unit

CAPITAL CHARGE RATE: A number used to convert the installed cost of a power project into a levelized capital cost that can be charged to the project in each year of the project life

CAPITAL COST: The total installed cost of equipment, emissions control, interconnections, gas compression, engineering, soft costs, etc. for landfill gas projects

COGENERATION: The consecutive generation of useful thermal energy and electric energy from the same fuel source

COMBINED-CYCLE: Technology in which waste heat from a gas turbine is used to produce steam in a waste-heat boiler; the steam is then used to generate electricity in a steam turbine/generator

CONDENSATE: Liquid formed when warm landfill gas cools as it travels through the collection system

COST OF CAPITAL: The cost to a company of acquiring funds to finance the company's capital investments and operations

DEBT COVERAGE RATIO: Ratio of operating income to debt service requirement, usually calculated on an annual basis

DEBT SERVICE REQUIREMENT: Monthly requirement to meet the principal and interest amounts of a loan

DISPLACEMENT SAVINGS: Savings realized by displacing purchases of natural gas or electricity from a local utility by using landfill gas

EPC FIRM: A company that provides engineering, procurement, and construction services

FLARE: A device used to combust excess landfill gas that is not used in energy recovery; flares may be open or enclosed

GREENHOUSE GAS: A gas, such as carbon dioxide or methane, which contributes to global warming

GROSS POWER GENERATION POTENTIAL: The installed power generation capacity that landfill gas flows can support

HEAT RATE: A measure of generating unit thermal efficiency, expressed in units of Btu/kWh

LOWEST ACHIEVABLE EMISSIONS RATE (LAER): The most stringent technology available for controlling emissions; major sources are required to use LAER (cost is not a consideration in determining the LAER technology)

MAJOR SOURCE: New emissions sources or modifications to existing emissions sources that exceed NAAQS emission levels

METHANE (CH₄): The major component of natural gas and landfill gas; produced in landfills when organic matter in waste decomposes

METRIC TON: Measurement of mass; one metric ton equals one megagram (Mg)

MINOR SOURCE: New emissions sources or modifications to existing emission sources that do not exceed NAAQS emission levels

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS): Air quality standards, established by the Clean Air Act, for six criteria pollutants

NET PRESENT VALUE (NPV): The amount of money, that if invested today at a given rate of return, would be equivalent to a fixed amount to be received at a specified future time

NEW SOURCE REVIEW (NSR): Process by which an air quality regulatory agency evaluates an application for a permit to construct a new generating facility

NONATTAINMENT AREA: A geographic region designated by the EPA that exceeds NAAQS for one or more criteria pollutants

NON-METHANE ORGANIC COMPOUNDS (NMOCs): Compounds found in landfill gas which affect human health and vegetation; NMOCs include several compounds that are known carcinogens to humans

PARASITIC LOAD: The electric load required to run generation equipment; contributes to the difference between gross and net output

PREVENTION OF SIGNIFICANT DETERIORATION (PSD): Regulations designed to limit the increase of criteria air pollutants in attainment areas

PRO FORMA: A computer model of project cash flows over the life of the project, usually containing several standard items

PROJECT FINANCE: A method for obtaining commercial debt financing for the construction of a facility where lenders look to the creditworthiness of the facility to ensure debt repayment, rather than to the assets of the project developer

PUMP TEST: A procedure used to determine the gas generation rate of a landfill; it involves drilling test wells and installing pressure probes

PUBLIC UTILITIES REGULATORY POLICIES ACT (PURPA): Act that requires utilities to purchase the electric output from QFs at the utility's avoided cost

QUALIFYING FACILITY (QF): A cogenerator or small power producer, as defined by PURPA, that is entitled to special regulatory treatment; utilities are required to purchase the electrical output from QFs at the utility's avoided cost

RATE OF RETURN (ROR) ON EQUITY: Financial measurement used to judge the percent of return on equity capital used in business

RENEWABLE ENERGY PRODUCTION INCENTIVE (REPI): Incentive established by the Energy Policy Act, that is available to renewable energy power projects owned by a state or local government or nonprofit electric cooperative

REQUEST FOR PROPOSALS (RFP): A solicitation by a utility for project proposals

ROYALTIES: Compensation given to a landfill owner for gas rights

SENIOR DEBT LENDER: Institution or person who lends money with the intention that the debt will be repaid before project earnings get distributed to equity investors

SOFT COSTS: Transaction and legal costs, escalation during construction, interest during construction, and contingency costs associated with a project

STANDARD OFFER: A power purchase agreement, sanctioned by the state utility commission, that is typically based on avoided costs

SUBORDINATED DEBT: Money that is repaid after any senior debt lenders are paid and before equity investors are paid

VOLATILE ORGANIC CHEMICALS (VOCs): Chemicals found in landfill gas that are contributors to smog

WHEELING: The transmission of electricity owned by one entity using the facilities owned by another entity (usually a utility)